NEWARK BAY STUDY AREA

ADDITIONAL SITES AND CANDIDATE PRPS FOR THE NEWARK BAY STUDY AREA

VOLUME I OF III

PRP DATA EXTRACTION FORM AND EVIDENCE CONCERNING:

ELIZABETHTOWN GAS COMPANY
ELIZABETH SITES

PREPARED BY:
TIERRA SOLUTIONS, INC.

SUBMITTED TO:
USEPA REGION II

MARCH 2008

99725

Elizabethtown Gas Company, Elizabeth, New Jersey Sites

CANDIDATE PRP(S):

PRP: Pivotal Utility Holdings, Inc. (as successor to Elizabethtown Gas Company ["ETG"])

CURRENT MAILING ADDRESS/CONTACT INFO:

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John Kean, Jr., President and CEO
P.O. Box 760
Bedminster, NJ 07921

BAC000005, BAC000006, BAC000013

FACILITY ADDRESS:

The Elizabethtown Gas Company ("ETG") has operated at two locations along the Elizabeth River in Elizabeth, Union County, New Jersey: the "Erie Street Site"; and the "South Street Site."

Erie Street Site:

200-234 Third Avenue
Elizabeth, Union County, New Jersey 07207

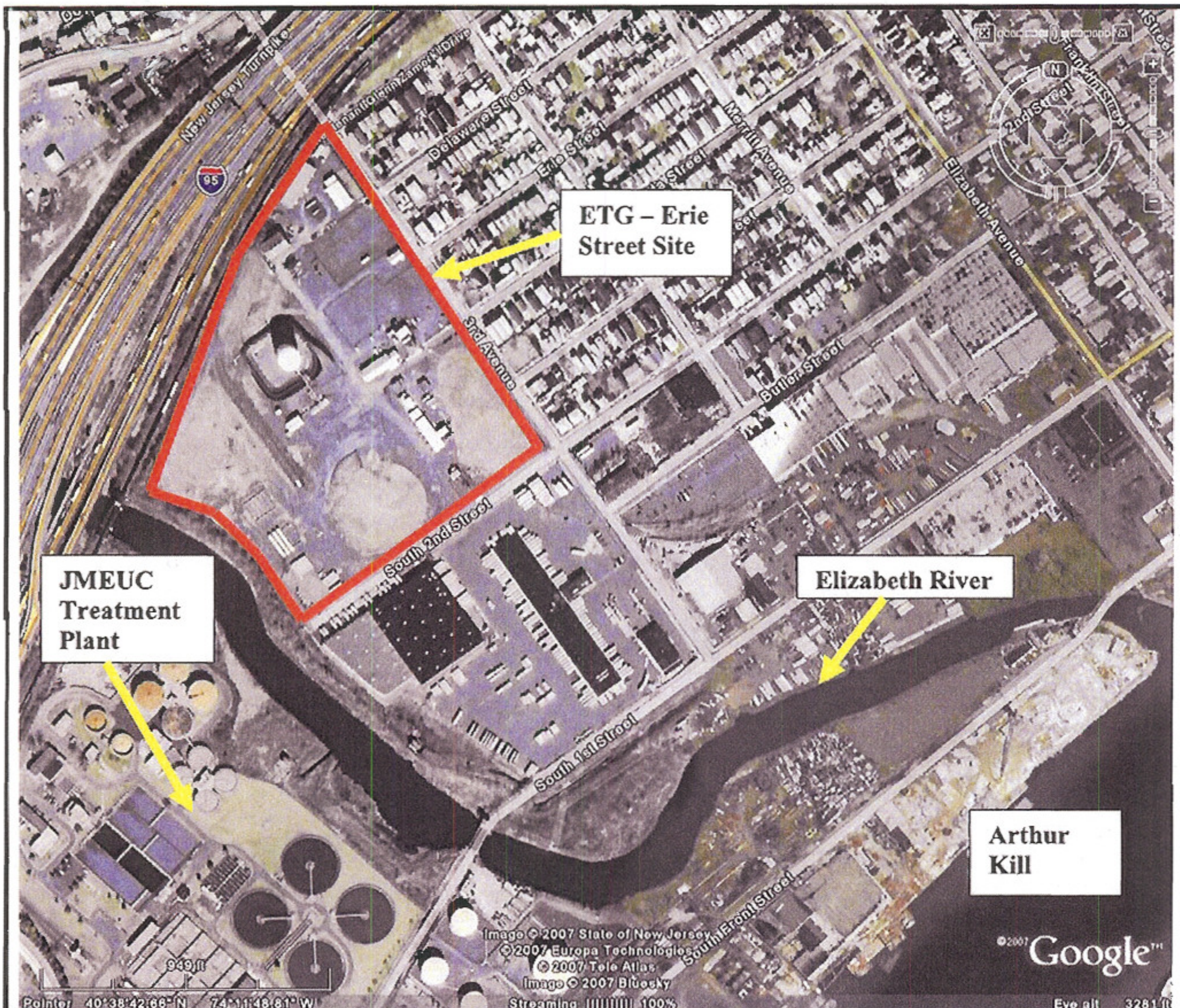
The Erie Street Site is comprised of a tract of land approximately 24.5 acres in size, located at Third Avenue between South 2nd Street and Delaware Street, and identified as Block 5, Lot 1381 on the City of Elizabeth, NJ tax map. The Site is bounded by: Third Avenue and residential properties to the northeast; South 2nd Street and a trucking company to the southeast; railroad tracks and the NJ Turnpike to the northwest; and the Elizabeth River to the southwest. The Erie Street Site is located at a point on the Elizabeth River approximately 0.7 miles upstream of its confluence with the Arthur Kill. BBA000004, BBA000006, BBA000011

South Street Site:

406 South Street
Elizabeth, Union County, New Jersey 07202

The South Street Site is comprised of a tract of land approximately 2.7 acres in size and identified as Block 9, Lot 1151 on the City of Elizabeth NJ tax map. The Site is bounded by: South Street and light industry to the north; Fourth Avenue and residential properties to the east; Centre Street and residential properties, and a portion of an Elizabeth Flood Control Basin, to the south; and the Elizabeth River to the west. The Route 1 & 9 viaduct crosses diagonally over the western portion of the Site (in a north-northeasterly direction from the southwest corner of the Site) at an approximately 30-foot elevation. The South Street Site is located at a point on the Elizabeth River approximately 2 miles upstream of its confluence with the Arthur Kill. BBA000030, BBA000044

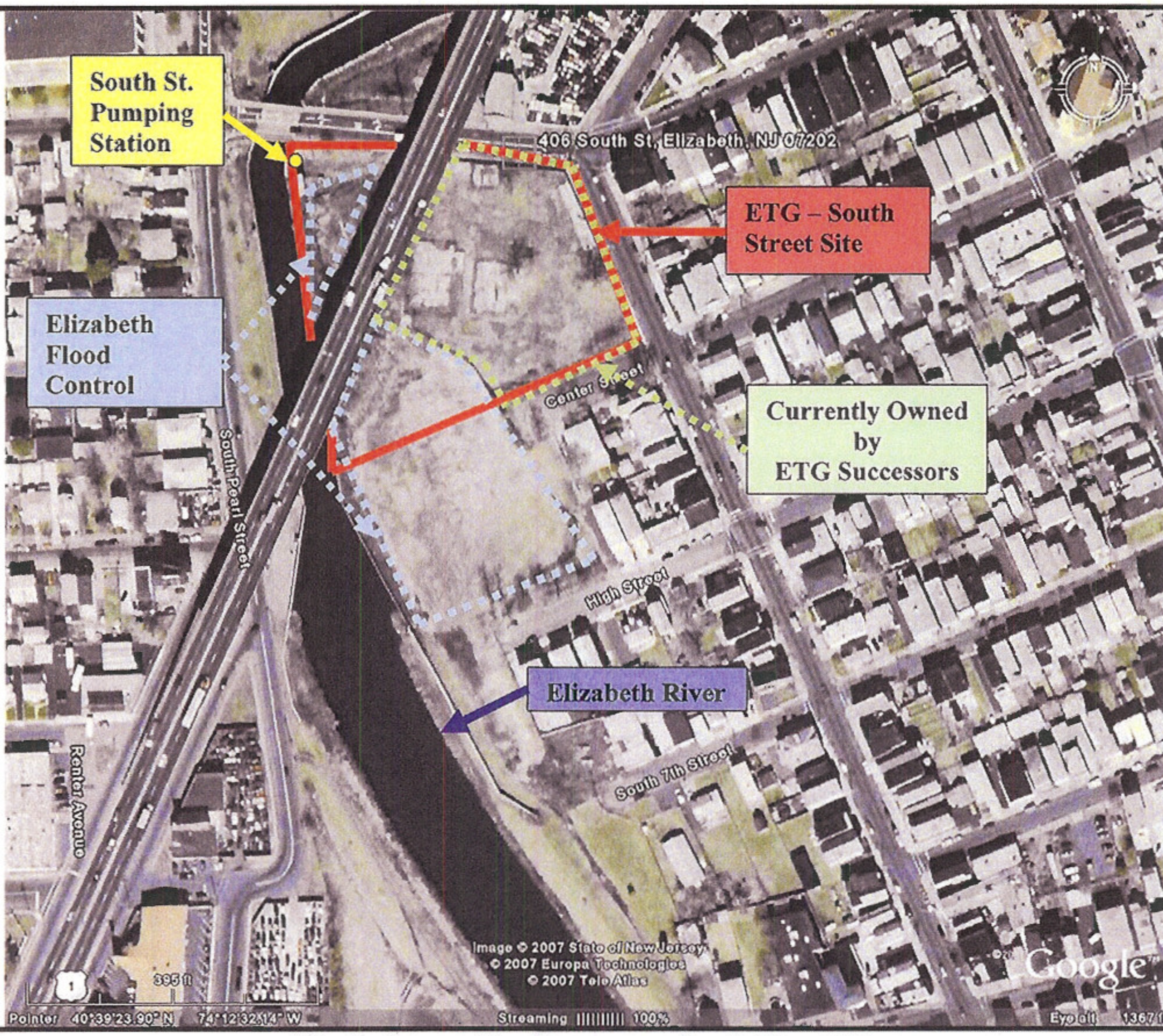
The approximate locations of the two ETG Sites are shown on the following annotated aerial photographs:



Elizabethtown Gas Company - Erie Street Site
200-234 Third Avenue
Elizabeth, Union County, NJ

Aerial photograph copyrighted 2007
Source: Google Earth (Europa Technologies/Tele Atlas/Bluesky)

Annotated Site outline and location is an approximation



Elizabethtown Gas Company - South Street Site
406 South Street
Elizabeth, Union County, NJ

Aerial photograph copyrighted 2007
Source: Google Earth (State of New Jersey/Europa Technologies/Tele Atlas)

Annotated Site outline and location is an approximation

FINANCIAL VIABILITY (annual revenue, # of employees)**:**

Pivotal Utility Holdings, Inc. ("Pivotal," parent company of ETG) is wholly owned by AGL Resources, Inc. ("AGL"), which has assumed responsibility for existing and future environmental remediation costs at all ETG sites. [*See* detailed discussion in the "Dates of Operation" section, below, of this Data Extraction Form.] AGL distributes natural gas to more than 2.2 million end-use customers through its public-utility company subsidiaries, including Pivotal, which owns and operates three utility divisions in New Jersey, Florida, and Maryland, one of which is ETG. Pivotal, through its ETG division, currently serves approximately 269,000 customers in Union, Middlesex, Sussex, Warren, Hunterdon, Morris, and Mercer counties in New Jersey. AGL reports having 2,385 employees and consolidated operating revenues of $2,621 million for 2006. BAC000005, BAC000006, BAC000007, BAC000009, BAC000014

DATES OF OPERATION (include info. on predecessors/successors if known)**:**

Erie Street Site:

The Metropolitan Gas Light Company, later purchased by ETG, had owned a 2-acre portion of the Erie Street Site since 1857 and began coal gas operations on the Site by 1889. ETG bought Metropolitan Gas Light Company, including the 2-acre property and additional properties to the west and southwest in 1892 to establish the 24.5-acre Erie Street Site. ETG successors continue to own the Site. (*See* additional "History, Ownership and Succession of ETG" below.) BBA000018, BAB000001

South Street Site:

The South Street Site was operated by ETG from 1855 to 1901. ETG continued to own the entire 2.7-acre Site until 1978-1980 when approximately half of the property was condemned and transferred to the City of Elizabeth for flood control projects. The Northern and Southern Retention Basins were created on the western portion of the Site adjacent to the Elizabeth River. ETG successors continue to own the remaining half of the original Site. (*See* additional "History, Ownership and Succession of ETG" below.) BBA000048

History, Ownership and Succession of ETG:

Information has been obtained on the following key dates in the history and corporate successorship of the Elizabethtown Gas Company:

- 1855 – 1922: Elizabethtown Gas Light Company was a corporation created in 1855 by an Act of the Legislature of New Jersey to fuel the 300 gas lights lining the streets of Elizabeth, NJ. BAC000001, BBC000001, BBC000010

  Elizabethtown Consolidated Gas Company was created in 1922 by an Agreement of Consolidation between Elizabethtown Gas Light Company, Metuchen Gas Light Company, Rahway Gas Light Company, and Cranford Gas Light Company. BBC000001, BBC000010

- 1966 – 1969: In 1966, Elizabethtown Consolidated Gas Company changed its name to Elizabethtown Gas Company ("ETG"). BBC000010

National Utilities & Industries Corporation was formed and incorporated in the State of New Jersey in January 1969. BBC000023

In April 1969, National Utilities & Industries Corporation acquired ETG through a stock exchange, whereby National Utilities & Industries Corporation exchanged shares of its common stock for the outstanding shares of ETG common stock. BBC000012, BBC000025

ETG was operated as a wholly-owned subsidiary of National Utilities & Industries Corporation. BBC000031

- 1983: National Utilities & Industries Corporation changed its name to NUI Corporation ("NUI"). BBC000026

- 1994 – 2000: In 1994, ETG was merged with and into NUI , with NUI continuing as the surviving corporation. BBC000031

  ETG became an operating division of NUI. BAC000002

  In 2000, NUI Holding Company ("NUI Holding") was incorporated in the State of New Jersey. BBC000018

- March 1, 2001: Pursuant to a Exchange Agreement, NUI Holding acquired all of NUI's stock, thereby making NUI Holding the parent corporation and NUI the subsidiary. BAC000003, BBC000020

  Subsequently, NUI Holding was renamed NUI Corporation, and the former NUI was renamed NUI Utilities, Inc. ("NUI Utilities"). BAC000003, BBC000019, BBC000033

- 2004: AGL Resources, Inc. ("AGL"), an Atlanta based Fortune 1000 energy services holding company trading on the New York Stock Exchange under ticker symbol "ATG" acquired NUI Corporation. The acquisition was accomplished by a merger of Cougar Corporation, a wholly owned subsidiary of AGL, with and into NUI Corporation, with NUI Corporation continuing as the surviving corporation. Pursuant to the Merger, AGL acquired all the outstanding shares of NUI Corporation for approximately $218 million, including the assumption of $709 million in debt; and AGL also assumed responsibility for existing and future environmental remediation costs at all the ETG sites. BAC000004, BAC000005, BAC000006, BAC000007, BAC000008, BAC000010

- 2005: NUI Utilities d/b/a Elizabethtown Gas Company (a division of NUI Utilities) changed its name to Pivotal Utility Holdings, Inc. ("Pivotal") d/b/a Elizabethtown Gas Company. BAC000012, BBC000037

ETG, a division of Pivotal, currently serves approximately 269,000 customers in Union, Middlesex, Sussex, Warren, Hunterdon, Morris and Mercer counties in New Jersey. AGL distributes natural gas to more than 2.2 million end-use customers through its public-utility company subsidiaries, including Pivotal, which owns and operates three utility divisions in New Jersey, Florida, and Maryland, one of which is ETG. AGL reports having 2,385 employees and consolidated operating revenues of $2,621 million for the 2006. BAC000005, BAC000006, BAC000007 BAC000009, BAC000014

DESCRIPTION OF FACILITY OPERATIONS (list CERCLA hazardous substances used, manufactured or present)**:**

Erie Street Site:

Since the beginning of operations at the Erie Street Site, utility gas has been produced, stored, and/or distributed at the Site. "Coal gas" was manufactured on the Site from at least as far back as 1889 until 1915. This gasification process involved the use of coal, coke, and oil. After 1915, coal gas production was replaced by carbureted water gas production, which generally utilized water in place of oil. Both processes, however, involved loading coal/coke into a furnace (retort) and the generation of tar as a by-product. By approximately 1927, 80,000 tons of coal was used per year; and by 1935, 500 million cubic feet of gas was produced per year. The original Site buildings consisted of a warehouse, main office, engine room, carpenter shop, boiler room, pump house, generator house, pipe shop, and a welding/blacksmith garage. Additionally, there were various aboveground storage units and five main gas holders on the Site, including Gas Holder No. 8 - built in 1947 with a 10 million cubic foot capacity - the largest in the world at that time. All of the original buildings were demolished in 1976. BAB000001

Poor quality byproducts and process waste, including coal, coke, slag, coal tar, oils and wood chips, were landfilled mostly in the southern portion of the Site "where they were used with other backfill materials to cover the marsh deposits" adjacent to the Elizabeth River. Historical photos show that the southern portion of the Site near the river was once swampland. Remedial investigations have shown that the fill is generally thickest (up to 10 feet) in this area. BBA000001, BBA000003

Regular gas production was discontinued in March 1951. The equipment was converted to use a different process to produce gas from coal only during high-demand periods. At that time, a new control system was built and the main business at the Site became the distribution of natural gas. In 1966, gas production ceased completely. An alternate fuel (propane air) plant was installed in 1974. Stored propane and air were mixed to produce a gas combustible with natural gas. Circa 1989, ETG began storing propane and liquid natural gas ("LNG") for peak usage. Natural gas was converted to LNG by decreasing its temperature. One cubic foot of LNG equals about 618 cubic feet of natural gas. The LNG was converted back into gas by three gas-fired vaporizers that transferred heat to a water bath, which vaporized the LNG. The Site continues to operate as an active natural gas storage and transfer facility. In June 1992, ETG signed a Memorandum of Agreement with the New Jersey Department of Environmental Protection ("NJDEP"), which required a remedial investigation and remedial action be conducted at the Site. BAB000001, BBA000006

When Gas Holder No. 8 was cleaned out (year unknown – likely around 1966 when production ceased) forty men reportedly were needed to clean the "muck" out of the bottom. A hole was cut in the side of the holder to hand bucket the muck out, but the location for the disposal of the waste was not reported. BAB000001

South Street Site:

Coal gas was produced on the Site from 1855 to 1901. Coal gasification processes resulted in the generation of wastes including: coke, coal tar, light oils, clinker, coal tar pitch, ammonia, and ammonium sulfate. Coal tar generally contains high levels of polynuclear aromatic hydrocarbons ("PAHs"). Tar wastes and spent oils were believed to have been disposed in unlined pits on Site. Materials identified by United States Environmental Protection Agency ("USEPA") contractors in 1990 as retort slag and coal tar were found in Site surface and subsurface soils. BBA000032

The original Site buildings consisted of a purifying house, a retort building, two coal sheds, an engine house, a blacksmith shop, two sheds, an office building, and two gas holders (storage tanks). All original buildings were demolished between 1959 and 1966, except for the retort house and office building which were still present as of 1990. BBA000032

From 1901 until 1965, ETG reportedly used the Site for engineering operations, pipeline storage, and dispatch for construction crews. In 1929, the New Jersey Department of Transportation ("NJDOT") began construction of the Routes 1 and 9 viaduct over the northwestern corner of the Site. After 1965, ETG leased the Site to Franklin Hudson, an architect. From 1974 to 1979, ETG leased the Site to Harvester Chemical Co., who did not operate on Site, but in turn subleased it to Vignola Salvage Corporation, a bank safe repair company. During the 1978-1980 timeframe, roughly the western half of the Site was condemned and transferred to the City of Elizabeth for flood control projects, including the Northern and Southern Retention Basins adjacent to the river. Beginning in 1980 to 1990, Vignola leased directly from ETG the remaining portion of the Site still owned by ETG; and Vignola, in turn sublet portions of the Site, generally for trucking and parking. BBA000040, BBA000044, BBA000048

NJDOT performed environmental investigations between 1987 and 1989 on a portion of the Site along the northern boundary related to the widening of the Routes 1 & 9 viaduct. Subsequently, this led to the signing of an Administrative Consent Order in April 1991 between NJDEP and ETG for the original 2.7-acre footprint owned historically by ETG. A Final Revised Remedial Investigation ("RI") Report was issued by ETG in October 1996. In 1998, due to delays in delineating contamination in the RI reports, NJDEP required ETG to combine the remaining delineation work and a Remedial Action Plan as a "Phase II Pre-Design Investigation." A revised version of the draft of that report was issued in February 2006. As of July 2007, source identification and delineation of a benzene groundwater plume continues. BBA000046, BBA000078, BBA000088

SOIL SAMPLING AND CONTAMINATION:

Erie Street Site:

Surface and sub-surface soil investigation analyses have detected the following hazardous substances, at the levels indicated, associated with Site operations:

Volatile Organic Compounds ("VOCs") including:

- Benzene at up to 320 parts per million ("ppm")
- Xylenes at up to 650 ppm

PAHs including:

- Acenaphthene at up to 12,000 ppm
- Anthracene at up to 7,300 ppm
- Benzo(a)anthracene at up to 2,700 ppm
- Benzo(b)fluoranthene at up to 660 ppm
- Benzo(a)pyrene at up to 1,700 ppm
- Benzo(k)fluoranthene at up to 1,400 ppm
- Chrysene at up to 2,600 ppm
- Dibenz(a,h)anthracene at up to 5.9 ppm
- Fluoranthene at up to 6,000 ppm
- Fluorene at up to 7,700 ppm
- Indeno(1,2,3-cd)pyrene at up to 620 ppm
- Naphthalene at up to 30,000 ppm
- Pyrene at up to 8,000 ppm

Metals including:

- Antimony at up to 28.1 ppm
- Arsenic at up to 868 ppm
- Barium at up to 2,560 ppm
- Cadmium at up to 90.9 ppm
- Copper at up to 3,120 ppm
- Lead at up to 48,500 ppm
- Mercury up to 41.6 ppm
- Thallium at up to 8.8 ppm
- Zinc at up to 4,390 ppm
- Cyanide at up to 1,420 ppm

BBA000011, BBA000018

South Street Site:

Surface and sub-surface soil investigation analyses have detected the following hazardous substances, at the levels indicated, associated with Site operations:

Coal tar product PAHs including:

- Acenaphthene at up to 220 ppm
- Anthracene at up to 500 ppm
- Benzo(a)anthracene at up to 2,500 ppm
- Benzo(b)fluoranthene at up to 1,500 ppm
- Benzo(k)fluoranthene at up to 1,400 ppm
- Benzo(a)pyrene at up to 1,900 ppm
- Chrysene at up to 2,800 ppm
- Dibenz(a,h)anthracene at up to 570 ppm
- Fluoranthene at up to 1,300 ppm
- Fluorene at up to 2,500 ppm
- Indeno(1,2,3-cd)pyrene at up to 1,000 ppm
- Naphthalene at up to 3,500 ppm

- Pyrene at up to 970 ppm
- Dibenzofuran up to 460 ppm
- 2,4-Dimethylphenol at up to 12 ppm

VOCs including:
- Benzene at up to 82 ppm
- Ethylbenzene at up to 181 ppm
- Total xylenes at up to 403 ppm

Metals including:
- Arsenic at up to 38.4 ppm
- Barium at up to 1,430 ppm
- Beryllium at up to 1.5 ppm
- Cadmium at up to 1.9 ppm
- Lead at up to 2,470 ppm
- Mercury at up to 34.7 ppm
- Thallium at up to 2.7 ppm
- Zinc at up to 3,980 ppm
- Cyanide at up to 2.4 ppm

BBA000044, BBA000078

GROUNDWATER SAMPLING AND CONTAMINATION:

Erie Street Site:

Groundwater investigation analyses involving overburden and bedrock systems have detected the following hazardous substances, at the levels indicated, associated with Site operations:

VOCs including:
- Benzene at up to 140,000 parts per billion ("ppb")
- Ethylbenzene at up to 2,200 ppb
- Xylenes at up to 3,600 ppb

Semivolatile Organic Compounds ("SVOCs") including:
- 2-Methylnaphthalene at up to 1,100,000 ppb
- Acenaphthene at up to 260,000 ppb
- Anthracene at up to 150,000 ppb
- Benzo(a)anthracene at up to 64,000 ppb
- Benzo(b)fluoranthene at up to 22,000 ppb
- Benzo(k)fluoranthene at up to 35,000 ppb
- Benzo(a)pyrene at up to 57,000 ppb
- Benzo(g,h,i)perylene at up to 21,000 ppb
- Chrysene at up to 78,000 ppb
- Dibenz(a,h)anthracene at up to 15,000 ppb
- Dibenzofuran at up to 37,000 ppb
- Fluorene at up to 190,000 ppb
- Fluoranthene at up to 120,000 ppb

- Indeno(1,2,3-cd)pyrene at up to 17,000 ppb
- Naphthalene at up to 1,400,000 ppb
- Phenanthrene at up to 610,000 ppb
- Pyrene at up to 160,000 ppb

Metals including:
- Antimony at up to 272 ppb
- Arsenic at up to 142 ppb
- Barium at up to 2,200 ppb
- Beryllium at up to 5 ppb
- Cadmium at up to 22.1 ppb
- Lead at up to 237 ppb
- Manganese at up to 23,500 ppb
- Silver at up to 37 ppb
- Thallium at up to 10.4 ppb
- Zinc at up to 14,500 ppb
- Ammonia at up to 5,900 ppb
- Cyanide at up to 14,400 ppb (adjacent to the Elizabeth River)

BBA000013, BBA000018

Groundwater beneath the Erie Street Site is reported to most likely flow to the southwest toward the Elizabeth River. BBA000004

South Street Site:

Groundwater investigation analyses involving overburden and bedrock systems have detected the following hazardous substances, at the levels indicated, associated with Site operations:

Coal tar product VOCs including:
- Benzene at up to 4,000 ppb
- Toluene at up to 1,400 ppb
- Xylenes at up to 1,100 ppb

SVOCs including:
- 2-Methylphenol at up to 580 ppb
- 4-Methylphenol at up to 1,500 ppb
- 2,4-Dimethylphenol at up to 1,200 ppb
- Naphthalene at up to 2,700 ppb
- 2-Methylnaphthalene at up to 290 ppb
- Dibenzofuran at up to 130 ppb

Metals including:
- Antimony at up to 40.1 ppb
- Arsenic at up to 516 ppb
- Cadmium at up to 6.7 ppb
- Lead at up to 85.8 ppb
- Manganese at up to 4,890 ppb
- Cyanide at up to 3,900 ppb

BBA000044, BBA000046, BBA000078, BBA000086

The direction of groundwater flow in both the overburden and bedrock zones is toward the Elizabeth River. BBA000086

SEDIMENT AND SURFACE WATER SAMPLING AND CONTAMINATION:

Erie Street Site:

An "evaluation of the impact of the Erie Street former MGP site on the Elizabeth River sediments" was performed during the Remedial Investigation. Sediment samples collected from an Elizabeth River transect adjacent to the Site contained the following hazardous substances associated with Site operations:

PAHs including:

- 2-Methylnaphthalene at up to 160 ppm
- Acenaphthene at up to 73 ppm
- Anthracene at up to 44 ppm
- Benzo(a)anthracene at up to 23 ppm
- Benzo(b)fluoranthene at up to 12 ppm
- Benzo(k)fluoranthene at up to 14 ppm
- Benzo(a)pyrene at up to 15 ppm
- Benzo(g,h,i)perylene at up to 12 ppm
- Chrysene at up to 27 ppm
- Dibenz(a,h)anthracene at up to 2.7 ppm
- Dibenzofuran at up to 7.9 ppm
- Fluorene at up to 42 ppm
- Fluoranthene at up to 44 ppm
- Indeno(1,2,3-cd)pyrene at up to 9.1 ppm
- Naphthalene at up to 160 ppm
- Phenanthrene at up to 140 ppm
- Pyrene at up to 78 ppm

Metals including:

- Arsenic at up to16 ppm
- Cadmium at up to 18 ppm
- Copper at up to 334 ppm
- Lead at up to 980 ppb
- Manganese at up to 397 ppm
- Silver at up to 11.7 ppm
- Zinc at up to 795 ppm
- Cyanide at up to 1.34 ppm

BBA000018

As stated in the Supplemental Remedial Investigation Report, groundwater contamination is present in the overburden zone adjacent to the Elizabeth River and likely discharges to the river. Therefore, surface water samples were collected from the Elizabeth River to determine any impacts from Site groundwater. Analysis of a surface water sample collected downstream from the Site in the Elizabeth River detected the following hazardous substances associated with Site operations:

- Arsenic
- Thallium

These contaminants were detected at levels exceeding the NJDEP saline estuary Class 3 Surface Water Quality Criteria. BBA00018

Analysis of a surface water sample collected from a catch basin discharging to the Elizabeth River detected Benzene at 8.1 ppb. BBA000016

South Street Site:

Surface water from the Northern Retention Basin on the western portion of the Site contained the following hazardous substances, at the levels indicated, associated with Site operations:

PAHs including:
- Benzo(a)anthracene at up to 27 ppb
- Benzo(b)fluoranthene at up to 2 ppb
- Benzo(k)fluoranthene at up to 2 ppb
- Benzo(a)pyrene at up to 2 ppb
- Chrysene at up to 2 ppb

Metals including:
- Arsenic at up to 4.7 ppb
- Manganese at up to 319 ppb
- Cyanide at up to 11.4 ppb
- Total Phenols at up to 15 ppb

BBA000044

PERMITS (provide dates)**:**

Erie Street Site:

<u>NJPDES</u>:

NJ0063746 – This emergency permit was issued in November 1986 authorizing the discharge to ground water ("DGW") for an aquifer pump test. BBA000002

South Street Site:

No information is available at this time.

NEXUS TO NEWARK BAY STUDY AREA (describe in detail; cite to supporting documentation; date or time period of disposal; list CERCLA hazardous substances and volume, if known):

Direct (e.g. pipe, outfall, spill):

Erie Street Site:

The Elizabeth River creates the southwest boundary of the Site. BBA000004

A 1990 EPA Site Inspection Report indicated that prior to 1950, ammonia liquor, a process waste, was reportedly disposed of by mixing with cooling water and discharging to the nearest waterway – the Elizabeth River, a tributary to the Arthur Kill within the Newark Bay Study Area. No information is available at this time regarding the disposition of other process wastes. BBA000004

The Elizabeth River, a waterway within the Newark Bay Estuary, has been impacted by hazardous substances discharged from the Site. Site-related hazardous substances have been detected in sediment samples from the Elizabeth River, within 1 mile of the Newark Bay Study Area, as described above. BBA000004, BBA000016, BBA000018

South Street Site:

The City of Elizabeth (the "City") did not construct the Westerly Interceptor Sewer (the "Westerly Interceptor"), to divert discharges to the Joint Meeting of Essex and Union Counties ("JMEUC") treatment plant, until 1906; therefore, all wastewaters from the Site would have discharged directly to the Elizabeth River. BAA000061

Sanitary Sewer (provide name and location of Combined Sewer Outfall ("CSO"); details regarding CSO overflows and dates):

Erie Street Site:

Prior to 1957, wastewaters generated at the Site would have been discharged directly to the Elizabeth River. In 1957, the City completed the construction of an Easterly Interceptor Sewer (the "Easterly Interceptor") to divert discharges to the JMEUC treatment plant. Based upon information obtained to date, it is not known for sure if the Site was ever connected into the Easterly Interceptor. Wastewaters that continued to be discharged from the Site to the City sewer system, which is a combined sewer system, were subject to overflows during rainfall events. BAL000001, BBA000004

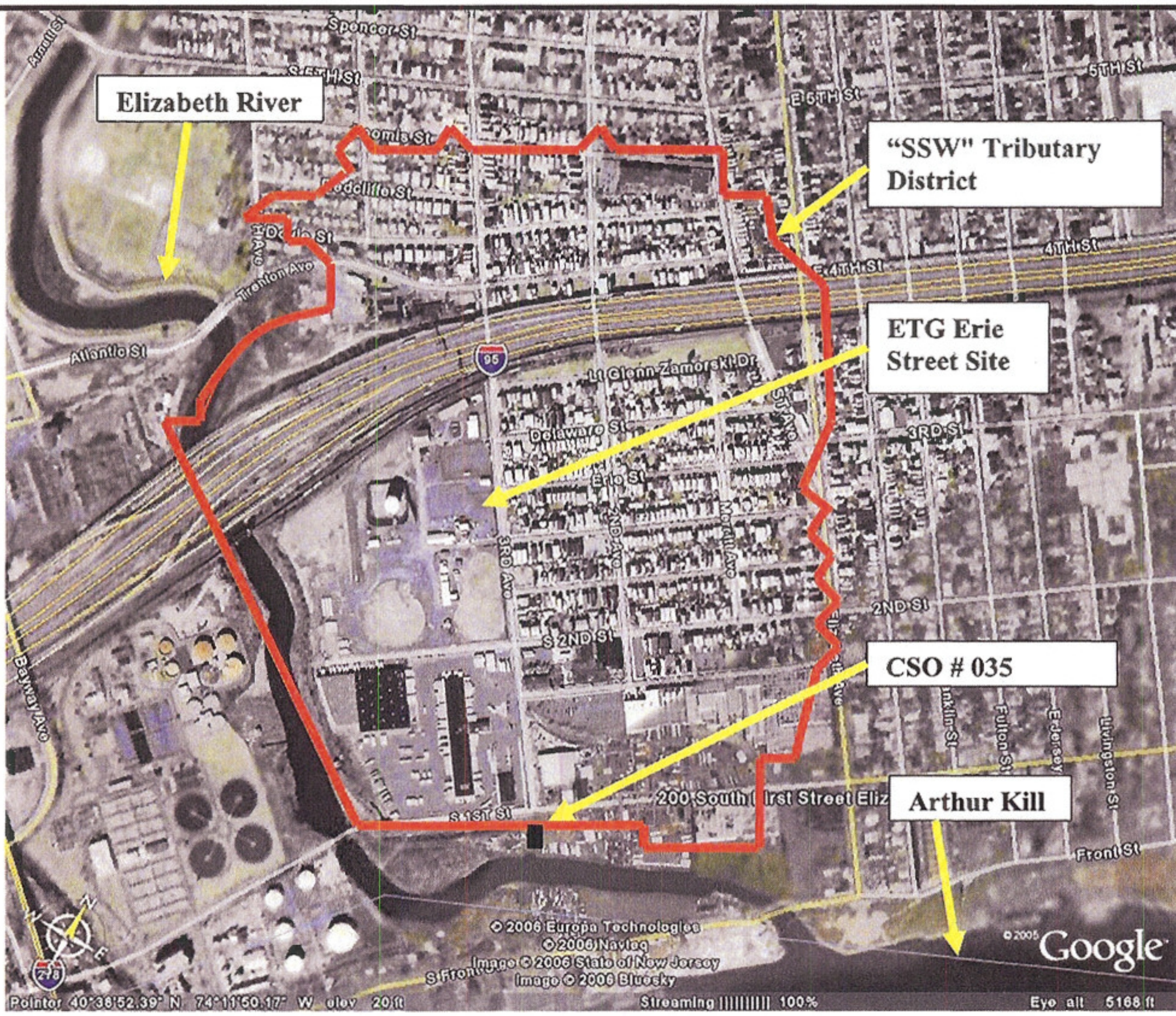
The City was issued NPDES Permit No. NJ0020648 by the USEPA on November 30, 1978 to discharge wastewaters from various combined CSOs to the Elizabeth River, Woodruff Creek, the Arthur Kill, Newark Bay, and the Great Ditch. This permit was later combined in 1992 with JMEUC NJPDES Permit No. NJ0024741. BAB000135, BAJ000001, BAL000005

The 1992 combined NJPDES permit for JMEUC and the City included CSO Number 035, located south of the foot of Third Avenue in Elizabeth, as a "permitted" discharge to the Elizabeth River. BAB000135, BAB000162, BAJ000001, BAL000003, BAL000005

As a result of NJDEP's development of a general permit for Combined Sewer Systems that was consistent with the National CSO Control Policy, the City was issued Individual Authorization No. NJ0108782, under the General Permit for Combined Sewer Systems NJPDES No. NJ0105023. The permit had an effective date of February 29, 2000 and an expiration date of February 28, 2005. BAG000002, BAJ000001

The Site is located within the City's "Area SSW" sewer system tributary district, which is connected to the Third Avenue CSO. Of Note, the CSOs that are located in this district are within one mile or less of the Arthur Kill. BAL000001, BAL000003, BAL000005, BAJ000001

The following annotated aerial photograph identifies the approximate location of the Site within the "Area SSW" tributary district and of the Third Avenue CSO in Elizabeth, New Jersey:



Elizabethtown Gas Company- Erie Street Site
Including Area SSW Tributary District and Third Avenue Outfall
Elizabeth, Union County, New Jersey

Aerial photograph copyrighted 2006
Source: Google Earth (Europa Technologies/Navteq/State of New Jersey/Bluesky)

Annotated Site outline and location is an approximation

South Street Site:

Since Site operations were discontinued in 1901 and the Westerly Interceptor was not constructed until 1906, wastewaters from the Site were never diverted to the JMEUC treatment plant. All wastewaters from the Site were discharged directly to the Elizabeth River through the City sewer system. BBA000016, BBA000032

Storm Sewer:

Erie Street Site:

Although storm drains in the Site area discharge to the Elizabeth combined sewer system and Site stormwater was reportedly filtered prior to discharge, another abandoned stormwater drainage system was discovered in January 2007, which had directed, and continued to direct, contaminated Site stormwater directly to the Elizabeth River via an outfall from a swale. The stormwater swale runs north to south down the center of the Site and includes catch basins that convey the water to the outfall. One of the catch basins was shown to be connected to the river during the tidal survey originally reported in April 2001. Site stormwater collected at an outfall to the swale in January 2007 was found to contain 8.1 ppm benzene. BBA000016, BBA000018

As of June 2007, it was unclear whether an interim remedial measure was implemented to fully prevent this discharge, during both dry and wet weather, to the Elizabeth River. Further, NJDEP expressed concern that the source of the benzene contamination had not been addressed. BBA000021

South Street Site:

No information available at this time.

Runoff:

Erie Street Site:

Surface water runoff from the Site flows to the southwest toward the Elizabeth River. BBA000004

Preliminary investigations by ETG have revealed extensive PAH contamination in the soil, which also contains concentration levels of volatiles and metals (lead and arsenic) above NJDEP Residential and Non-Residential Direct Contact Soil Cleanup Criteria. BBA000019

Historic aerial photographs show drainage channels running southeast across the Site to the Elizabeth River. BBA000003

South Street Site:

Following the 1978/1980 acquisition of a portion of Site property by the City for flood control, Site areas adjacent to the Elizabeth River were converted to retention basins by the Army Corps of Engineers. The retention basins are several feet lower in elevation than the remainder of the Site, allowing Site runoff to the basins. Water gates in the flood control embankments "allow surface water to drain from the site into the river during periods of low tide...During high tides, a pump discharges runoff water into the river." Storm sewers in the area direct stormwater from the eastern portions of the Site and adjacent areas to the retention basins. Site surface soil is contaminated as characterized above. BBA000044, BBA000078

Groundwater:

Erie Street Site:

Groundwater beneath the Erie Street Site is reported to most likely flow to the southwest toward the Elizabeth River. BBA000004

There are three groundwater systems beneath the Site. The water table in the soil aquifer zone (shallow overburden Zone A) adjacent to the southern Site boundary is 2.5 to 7.5 below ground surface, i.e. within the fill layer in the former marsh area. Groundwater flow in the direction of the river is restricted by the flood control wall/embankment at the northern end of the Site; however, the flow is channeled by the wall southward to the point where the wall ends and the groundwater is discharged to the river. Shallow overburden Zone A groundwater is contaminated as identified above. The shallow bedrock groundwater, which is tidally influenced by the Elizabeth River, is also contaminated as identified above. BBA000018

Preliminary investigations by ETG have revealed groundwater contamination with volatile organics and metals, including cyanide, at concentrations above NJDEP Groundwater Quality Standards. BBA000019

A February 2007 NJDEP memo notes that, due to lack of remedial action to remove product and related contamination in subsurface soils and groundwater along the river, discharge is "ongoing." Site groundwater is contaminated as identified above. BBA000013, BBA000017, BBA000018

South Street Site:

No information is available at this time.

POTENTIAL NEXUS TO NEWARK BAY STUDY AREA (describe in detail; cite to supporting documentation; list CERCLA hazardous substances and volume, if known):

Direct (e.g. pipe, outfall, spill):

Erie Street Site:

Preliminary investigations by ETG have revealed potential impacts to the adjacent Elizabeth River. BBA000019

A June 1990 Final Draft Site Inspection Report prepared for USEPA states:

> "...groundwater is presumed to flow to, and be in direct hydraulic connection with, the Elizabeth River. Wastes deposited on site are known to be in contact with groundwater underlying the site. Therefore, there is a potential release of contaminants to surface water through groundwater."

BBA000004

An abandoned Site drainage system was investigated in January 2007 due to continued discharge to the Elizabeth River. The system consisted of a 24-inch sewer line side-by-side with a 10-inch sewer line running down the center of the property from the original manufacturing area to the Elizabeth River. The structure of the system may indicate historical use as a process wastewater disposal system. BBA000016

Historic aerial photographs show drainage channels running southeast across the Site to the Elizabeth River. BBA000003

South Street Site:

No additional information available at this time.

Sanitary Sewer (provide name and location of combined sewer outfall ("CSO"); details regarding CSO overflows and dates):

Erie Street Site:

A 1990 EPA Site Inspection Report indicated that stormwater was discharged to the sanitary sewer rather than directly to surface water (the Elizabeth River). It is not known when stormwater began discharging to the sanitary sewer. A 1921 Elizabeth sewerage plan map does not show any Site storm drains; it does show storm drains in Third Avenue along the eastern side of the Site. A 1998 Sewer System Map of the City of Elizabeth shows the sewer line in Third Avenue connected to CSO 035. Since storm drains in the area of the Site discharge to the combined sewer system, stormwater from the Site could be discharged to the Elizabeth River via the Third Avenue CSO during events of heavy flow as described above. Although stormwater was reportedly "filtered" before leaving the Site, the potential exists that it could contain dissolved (unfilterable) contaminants. BAL000005, BBA000004, BBA000016, CAA000003

An old brick sewer line in Third Avenue is believed to intercept Site groundwater. Site groundwater is contaminated as identified above. This combined sewer system discharges via the Third Avenue CSO to the Elizabeth River, as described above, during events of heavy stormwater flow. BBA000018

South Street Site:

No additional information is available at this time.

Storm Sewer (provide name and location of CSO; details regarding CSO overflows and dates):

Erie Street Site:

Catch basins are located on the perimeter of the Site along Third Avenue and South 2nd Street. The Third Avenue CSO is described above.

South Street Site:

No additional information is available at this time.

Runoff:

Erie Street Site:

The Site is waterfront to the Elizabeth River. It is probable that runoff from the Site containing hazardous substances reached the Elizabeth River, which is a tributary to the Arthur Kill/Newark Bay. BBA00004

South Street Site:

The Site is waterfront to the Elizabeth River. It is probable that runoff from the Site containing hazardous substances reached the Elizabeth River, which is a tributary to the Arthur Kill/Newark Bay.

Groundwater:

Erie Street Site:

A June 1990 Final Draft Site Inspection Report prepared for USEPA reported:

> "... poor quality tars and oils have been deposited in unlined pits on site in the past...waste pits present a high potential for groundwater contamination since contaminants could leach through soil to groundwater ...suspected contaminants include pyrene, anthracene, and other PAHs."

BBA000004

South Street Site:

Although the Elizabeth River is now contained by a concrete flume, contaminated groundwater may have directly discharged to the river prior to completion of the flume circa 1978-1980. BBA000044

REFERENCES

TAB NO.	BATES NO.	DATE	DESCRIPTION
1	BAB000001	1989	Illuminations - The History of Elizabethtown Gas by Katharine Kean Czarnecki, Edited by John Kean
2	BAB000135	1992	NNDEP Fact Sheet for NJPDES Permit to Discharge for Joint Meeting and City of Elizabeth
3	BAB000162	06/1965	The Interstate Sanitation Commission and the City of Elizabeth – A Case Study in Intergovernmental Enforcement (incomplete)
4	BAC000001	09/12/07	Elizabethtown Gas-About Us, www.elizabethtowngas.com
5	BAC000002	03/15/95	NUI Corp·8-K·For 3/15/95·EX-99, Restructuring Plan Announced, www.secinfo.com/d25Z3.at.d.htm
6	BAC000003	03/02/01	NUI Corp·8-K·For 3/1/01·EX-99, Current Report, www.secinfo.com/drD1f.43d.htm

7	BAC000004	11/30/07	Dunn & Bradstreet report for NUI Corporation, www.dnb.com
8	BAC000005	11/30/07	AGL Resources-Investor Relations-Quick Facts, www.aglr.com
9	BAC000006	2006	AGL Resources 2006 Annual Report (excerpts)
10	BAC000007	2005	AGL Resources 2005 Annual Report (excerpts)
11	BAC000008	2004	AGL Resources 2004 Annual Report
12	BAC000009	11/27/07	AGL Resources-About Us-Our Business-Distribution Operations, www.aglr.com/about/distribution_eil.aspx
13	BAC000010	11/24/04	SEC, AGL Resources, Inc. et al; Order Authorizing Acquisition of NUI Corporation and its Subsidiaries, Various Financing Transactions, Reservation of Jurisdiction, www.sec.gov/divisions/investment/ opur/filing/35-27917.htm
14	BAC000012	10/08/07	Public Utility Companies CY 2006-NJ Taxation, www.nj,gov/treasury/taxation/taxexemption.htm
15	BAC000013	12/03/07	Dunn & Bradstreet report for Pivotal Utility Holdings, Inc., www.dnb.com
16	BAC000014	09/28/05	SEC AGL Resources Inc. Order Authorizing the Acquisition of Nonutility Business and Participation in the System Money Pool, www.sec.gov/divisions/ investment/opur/filing/35-280238.pdf
17	BAG000002	08/27/99	Letter from NJDEP to the Hon. Robert Menendez
18	BAJ000001	02/28/00	Letter from NJDEP to Hon. Mayor J. Christian Bollwage enclosing NJPDES General Permit #NJ0105023 and NJPDES Individual Permit #NJ0108782 for the City of Elizabeth
19	BAL000001	08/1981	City of Elizabeth *Combined Sewer Overflow Pollution Abatement Program, Volume II* draft report prepared by Clinton Bogert Associates (excerpts)
20	BAL000003	06/1993	City of Elizabeth *Combined Sewage Overflow Abatement Strategy* prepared by Clinton Bogert Associates (excerpts)
21	BAL000005	01/25/99	City of Elizabeth *CSO Solids/Floatables Control Facilities Preliminary Design Report* prepared by Killam Associates (excerpts)
22	BBA000001	07/06/84	Letter from ETG to NJDEP Re: Response to Information Request Dated 2/29/84
23	BBA000002	07/31/86	Letter from NJDEP to ETG Re: Issuance of Emergency NJPDES DGW Permit NJ0063746
24	BBA000003	02/23/89	*Preliminary Site Investigation - Erie Street Site* prepared by Dames & Moore
25	BBA000004	06/22/90	*Field Investigation Team Activities at Controlled Hazardous Substances Facilities - Zone 1* prepared by NUS Corp. for USEPA
26	BBA000006	06/19/92	Memorandum of Agreement between NJDEP & ETG
27	BBA000011	05/05/97	Internal NJDEP Memo Re: Phase I Supplemental Remedial Investigation Work Plan
28	BBA000013	09/27/99	*Phase I Supplemental Remedial Investigation Work Plan, Volume 1 of 4* prepared by GEI Consultants, Inc.

			(excerpts)
29	BBA000016	01/30/07	Letter from ETG to NJDEP Re: Project Summary for Water Drainage Issue prepared by GEI Consultants
30	BBA000017	02/08/07	NJDEP Handwritten Notes Re: Review of Progress Report
31	BBA000018	03/30/07	*Phase I Supplemental Remedial Investigation Report, Volume I* prepared by GEI Consultants (excerpts)
32	BBA000019	04/27/01	*Phase I Supplemental Remedial Investigation Report, Volume II* (corrected 1/21/04) prepared by GEI Consultants (excerpts)
33	BBA000021	06/29/07	Internal NJDEP Memo Re: Water Drainage Summary
34	BBA000030	04/09/91	Letter from NJDEP to ETG Re: Administrative Consent Order
35	BBA000032	10/29/91	NJDEP Internal Memo Re: Preliminary Assessments/ Site Inspections
36	BBA000040	11/29/93	*Final Site Inspection Prioritization Report, Elizabeth Coal Gas Site #2, Volume 1 of 2* prepared by Roy F. Weston, Inc. (excerpts)
37	BBA000044	10/31/96	*Final Revised Remedial Investigation Report, South Street Former MGP Site, Volume 1* prepared by Dames & Moore
38	BBA000046	06/08/98	Letter from NJDEP to ETG Re: Remedial Investigation Report
39	BBA000048	05/2002	*Final Pre-Design Investigation Report & Preliminary Remedial Action Selection Report, South Street Former MGP Site, Volume 1 of 2* prepared by Langan Engineering & Environmental Services, Inc. (excerpts)
40	BBA000078	02/2006	*Revised Draft Phase II Pre-Design Investigation Report, South Street Former MGP Site* prepared by Langan Engineering & Environmental Services, Inc. (excerpts)
41	BBA000086	02/14/07	NJDEP Internal Memo Re: South Street MGP, Elizabeth; Phase II RIWP dated February 2006; RIR dated 11-01-06
42	BBA000088	04/17/07	NJDEP Internal Memo Re: 4/12/07 Meeting Minutes Regarding the Large Gas Holder & Other Groundwater Related Activities at South Street Site
43	BBC000001	11/01/22	Agreement of Consolidation between Elizabethtown Gas Light Co., Metuchen Gas Light Co., Rahway Gas Light Co., and Cranford Gas Light Co.
44	BBC000010	03/30/66	Amended Certificate of Incorporation Elizabethtown Gas Co. (formerly Elizabethtown Consolidated Gas Co.)
45	BBC000012	11/18/69	Statement of Cancellation of Reacquired Shares of Elizabethtown Gas Company
46	BBC000018	02/02/00	Certificate of Incorporation of NUI Holding Company
47	BBC000019	03/01/01	Amended and Restated Certificate of Incorporation of NUI Holding Company
48	BBC000020	03/01/01	Certificate of Exchange of NUI Corporation and NUI Holding Company

49	BBC000023	01/28/69	Certificate of Incorporation of National Utilities & Industries Corporation
50	BBC000025	06/16/69	Certificate of National Utilities & Industries Corporation
51	BBC000026	03/08/83	Certificate of Amendment to the Certificate of Incorporation of National Utilities & Industries
52	BBC000031	04/19/94	Certificate of Merger of Elizabethtown Gas Company With and Into NUI Corporation
53	BBC000033	03/01/01	Certificate of Amendment of Restated Certificate of Incorporation of NUI Corporation
54	BBC000037	03/11/05	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of NUI Utilities, Inc.
55	CAA000003	04/1921	Elizabeth Sewerage Plans Section N-9

ILLUMINATIONS

The History of Elizabethtown Gas

KATHARINE KEAN CZARNECKI

EDITED BY JOHN KEAN

Chapter Nine
Erie Street

Most of the original buildings at Erie Street are gone now. But the employees are especially proud of the 1889 marker that symbolizes the long history of gas men and women who worked at the plant and were the backbone of the company since the very beginning.

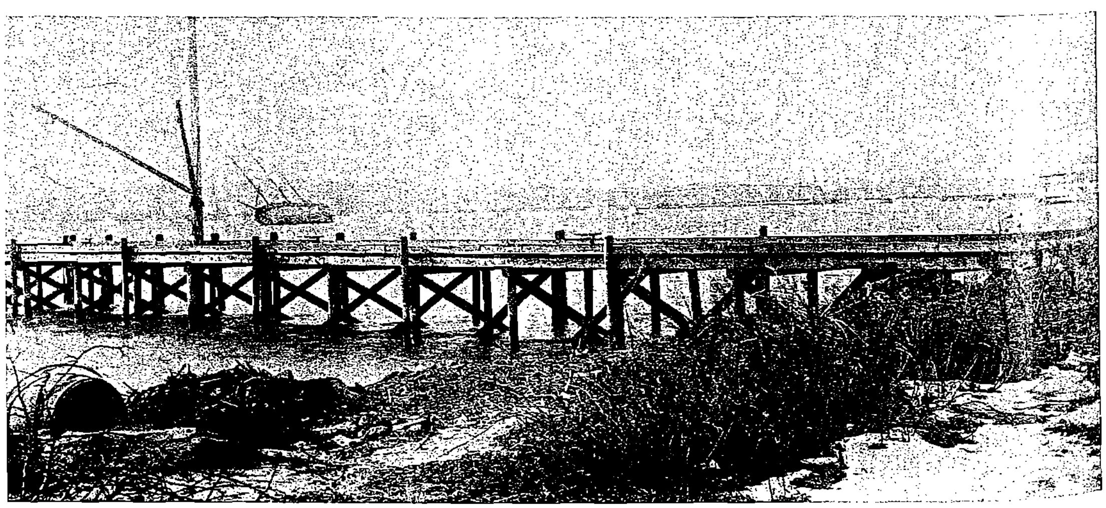
When the Elizabethtown Gas Light Company purchased the Metropolitan Gas Light Company in 1892, the acquisition included the gas manufacturing plant at Erie Street. Senator Hamilton Fish Kean recalled the early days. "I can remember in the 1870s when we breakfasted at seven o'clock in the morning and my father then drove in a buggy first to the saw mill and then to inspect the farm, and from there down to the old gas works, and there at the little house at the gate was a young man called Francis Engel, who was then superintendent of the works, and he would come out and stand by the buggy and tell my father all the news of what the out-put the night before had been, how much gas he made, and any other gossip there was about the works."

In those days coal was brought up the Elizabeth River in barges and unloaded by a bucket. The coal was stored in a shed which was opposite a bank of retorts. The men used wheelbarrows to transport the coal across the road to the retorts. These retorts were made by the Gautiers in Jersey City. All the shoveling was done by hand. The men, even in the winter, wore old trousers, shoes and undershirts. It required some skill to be able to toss the coal and spread it evenly over the bottom of a long retort. The heat from the burning coal was so great that the perspiration used to pour from the men as they worked.

After the retort was charged the men shut it and plastered handfuls of wet clay around the edges of the door to get it as nearly airtight as possible. After about eight hours the coal had been turned into coke. The door was opened, a long iron bar with a crosspiece on the end was thrust into the retort, the burning coke was pulled out into a steel barrow, and a man squirted water on it to cool it. It was then taken out and dumped in the coke pile.

Nearly everything around the works was hard hand labor. The men had to be well muscled and tough to stand it. In those days the tar left behind after the coal had been reduced to coke had to be pumped out by hand. Later, steam was used to pump the tar out.

The original process described above used soft coal to produce "coal gas." By about 1915, the process was changed and carbureted water gas was produced by converting coal, coke, steam and oil at temperatures ranging from thirteen hundred to two thousand degrees Fahrenheit. The gas was produced by spraying the hot coals with steam and oil. Huge air-blowers fanned the fires to the temperature required. Once the gas reached thirteen hundred degrees, pressure from the boilers forced it through a pipe into a saltwater condenser. In the condenser the gas was cooled, cleaned with a spray, pumped and then purified in a sulphur eliminating process before being stored in the gas holders. According to Bill Stansbury, who worked at Erie Street, "People used to bring their children down to the plant to inhale



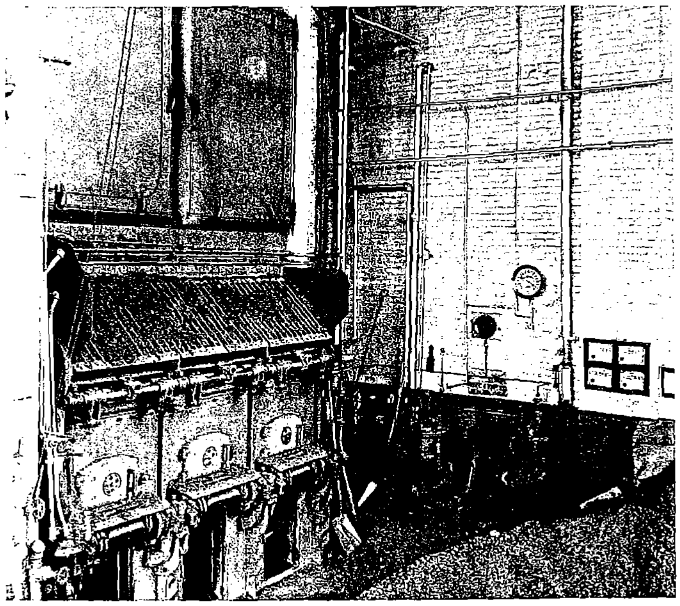
The dock at Erie Street on the Elizabeth River where the coal was unloaded, 1900. (Courtesy of John Tieman)

The gas makers at Erie Street, 1915.

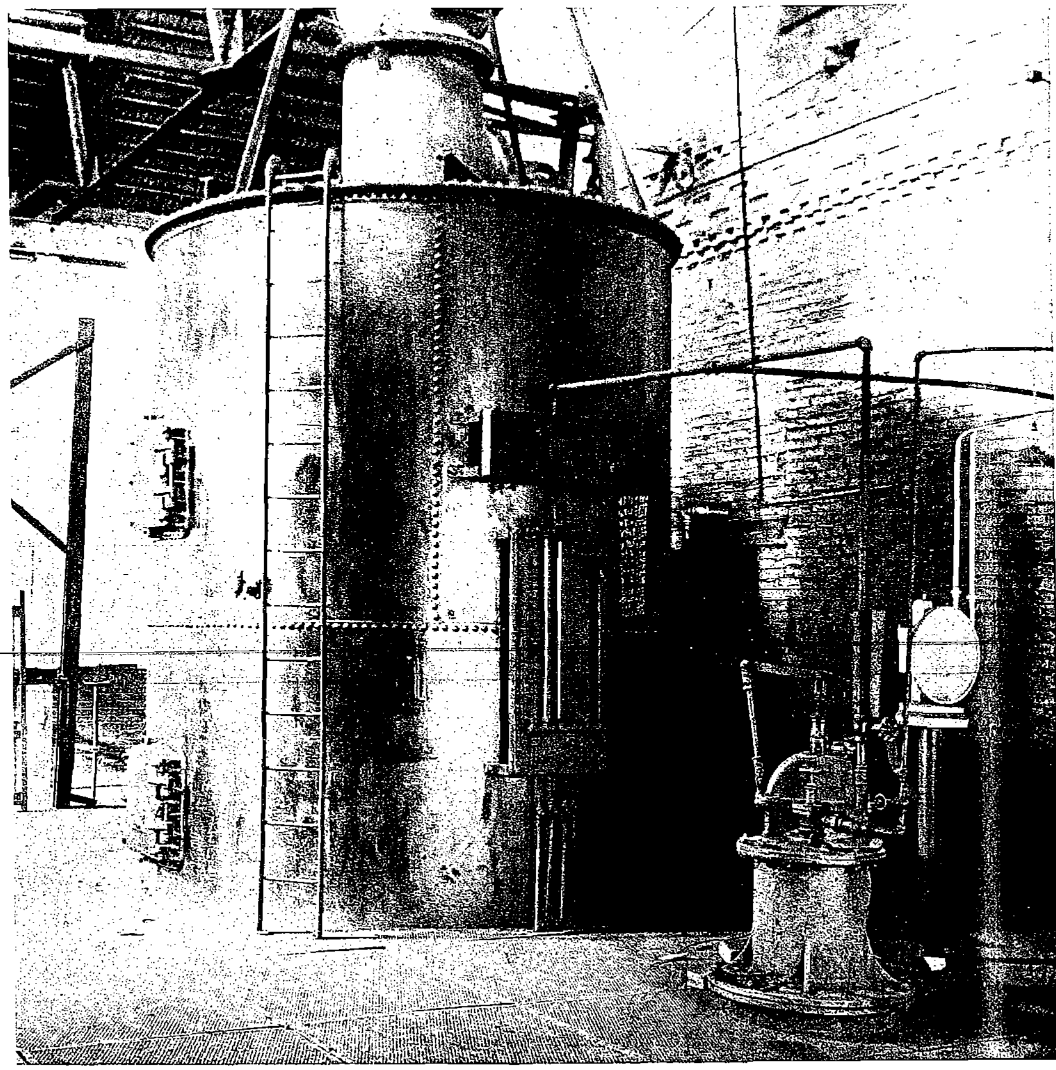
the sulphur because it was believed that it helped to relieve the whooping cough. Later on, they realized it was just an old wive's tale."

The pumps used in the process were of two types, exhausters and boosters. According to a 1934 Pilot Light, exhausters were operated by two impellers which rotated in opposite directions, causing a suction on one side and a pressure on the other. Pressure created by exhausters could range up to ten pounds above air pressure. The exhausters were used for transferring gas from the relief holder through the condensers, scrubbers and purifiers and finally into the storage holder, from which the gas went out into the distribution mains. The exhausters sucked the gas in and discharged it through the purifying apparatus at a pressure of about one pound per square inch.

Boosters were the familiar piston-type pumps, which could withstand pressures up to two thousand pounds. The booster pumps, used to maintain



The retort in the gas house. Coal was loaded into the furnaces to create carbureted water gas, 1930s.



The gas was stored in this tank before going into the purifying box. Pressure would build up inside of the tank and often the top would blow off. According to Bill Stansbury, "We would have to climb up to the top and use big hooks to pull the spout down out of the exhaust pipe."

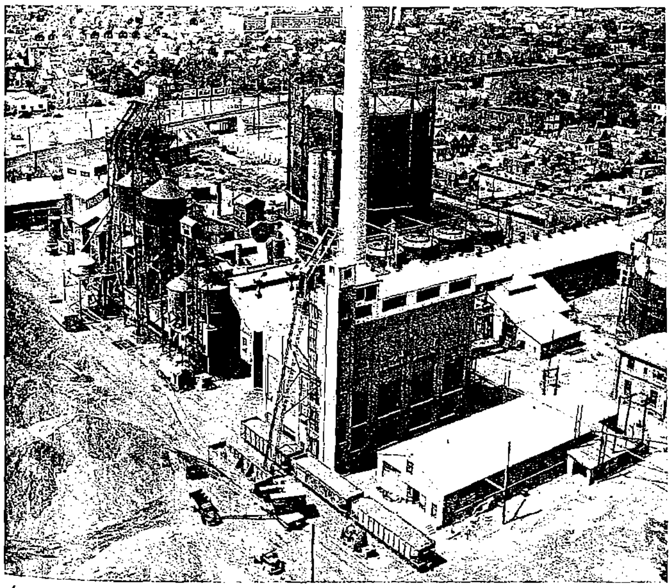
pressure in the mains, carried a pressure of fifteen pounds per square inch. They were capable of producing a pressure of thirty-five pounds per square inch, but attaining the limit of pressure was not necessary.

During this period barge loads of coal were brought up the Elizabeth River and hoisted high above the bunkers which were used to store the coal. The coal was then released into the fires, one carload every twenty minutes. As much as fifty thousand tons of coal were piled at one time in the yard anticipating peak days, or the possibility of a problem with deliveries. The barges came up the Elizabeth River until 1927, when the river was relocated in anticipation of the New Jersey Turnpike. After that time the railroad delivered twenty carloads of coal a day. About eighty thousand tons of coal were used each year.

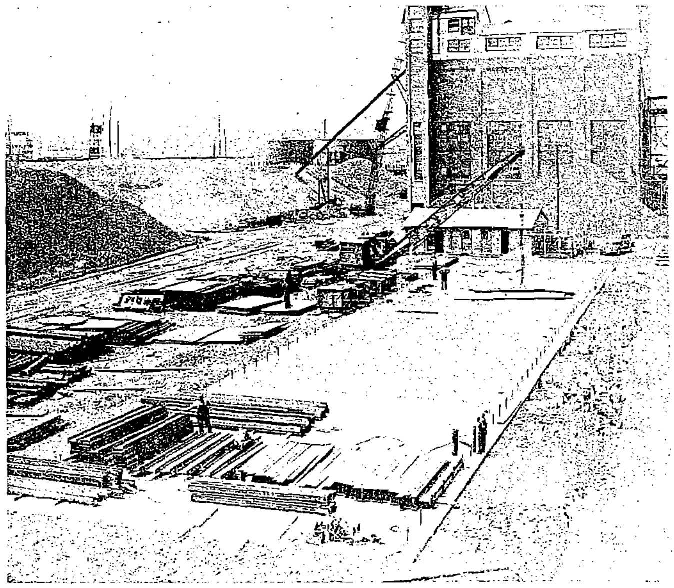
In 1946, there were forty-two hundred tons of coal piled in the yard, which was considered sufficient for only thirty days. There was a coal shortage at the time, and John J. Crilly, the superintendent, started to conserve the supply. Emlen Roosevelt, a member of the board, later remembered that John Crilly stored away so much coal that the company did not have to buy any for the last three months before the conversion in 1950.

The gas was quite toxic. Joe Millhiser, Sr., who worked for the street department for forty-three years, had a close call with it. The story was told by Frank Engel: "Gas masks had been developed during the war but were still completely new to our industry. Our company was endeavoring to teach the men to wear masks while working on leaks but they were more terrified of the masks than they were of the live gas. Therefore, the men were working without the masks and dropping like flies when they were overcome by the gas. Joe volunteered to be the guinea pig, donning a mask, fixing a major leak and walking off the job in perfect health. The men wore the masks without a complaint from that day on.

The gas house gang, April 13, 1932.



Aerial view of the Erie Street plant, June 1948.



The Erie Street yard in 1947 showing the foundation of the engine room. Notice the pile of coal at the left of the photo.

"Shortly after this incident, Joe arrived at the scene of an emergency and in his excitement, forgot to put on his mask. A few minutes later he tried to yell instructions to a member of the crew and ended up face down in a puddle. Joe was taken to the hospital and by the time he was revived all his clothes had been removed. The story becomes a little confused at this point. Some say Joe chased the nurses all over the hospital, while others say the nurses chased Joe. In any event he finally ended up in a straitjacket until the effects of the gas wore off."

Originally there were nine buildings on the property at Erie Street: the warehouse, the main office building, the engine room, the carpenter shop, the boiler room, the pump house, the generator house, the pipe shop and a building which contained a welding, machine, and blacksmith shop as well as a garage.

In 1976, most of the old buildings were demolished. Neil Schurig, manager of measurement and regulation, was part of the team that oversaw

THE GAS HOUSE CRILLYS

The Crilly family has been synonymous with the gas company since its early years. The first member of the family to work for the company was Roger Crilly, who was superintendent of the Third Avenue plant for forty-five years. Three of his seven children were employed by the gas company, including his eldest, John J., who worked as his assistant for twenty-four years. He also had a brother, James Crilly, who was a watchman at the Erie Street works.

Roger Crilly worked for the company eight hours a day, seven days a week. During his forty-five years of employment, he only missed a few weeks of work. When asked what he felt about his job he replied, "Work never hurt anyone nor prevented a person from increasing his knowledge."

Roger Crilly was born in Newcastle, England, in 1863 and started work at the age of eleven in the Burnet Chemical Company after only a few years of schooling. In 1886 he came to this country, where his first job was with Brown's Machine Shop on Third Street in Elizabeth. Soon after, he was hired as an engineer in the brickyard. It was there that he noticed some construction taking place on the adjacent farm, owned by the E. G. Brown estate. Mr. Crilly went to investigate and found that a new company, the Metropolitan Gas Light Company, was building a gas plant. That day, Roger was hired as an engineer to help in the construction of the new building.

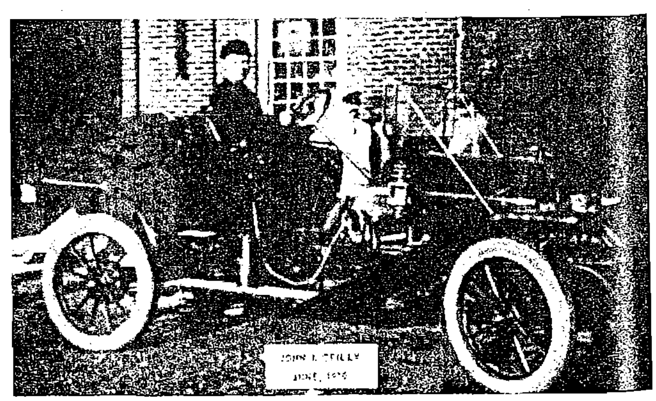
After three years, the Metropolitan Gas Light Company was acquired by the Elizabethtown Gas Light Company. At the time of purchase, there were only two small holders at the plant, one for crude gas and one for commercial gas, with a total capacity of 340,000 cubic feet. By the end of Roger Crilly's career, the plant had grown to be one of the most modern in the United States, with an annual production of 500 million cubic feet.

Roger Crilly was known as one of the most respected gas engineers in the country. It was said that experts would often ask his advice. Roger attended gas manufacturer's conventions to discuss his inventions, which had improved the production of illuminating gas. He conducted experiments which led to the process which separates water from tar.

Roger Crilly always rejected the idea of retiring, claiming that he could not stand quitting when he was blessed with good health. He was on the job every day, including Sundays and holidays. Some say he was as content working as he was sitting at home in an easy chair reading technical engineering books. He died of pneumonia at the age of seventy-one on February 8, 1935.


Francis Engel (left) and Roger Crilly (right) at the opening of the new H.P. Boiler House at Erie Street, 1931.

Roger's son, John J. Crilly, began work with the company as an automobile cleaner in 1910. He


John J. Crilly at fifteen in one of the company's first automobiles.

held numerous positions in the manufacturing plant before he was promoted to superintendent of gas production in 1935. In June of 1959, he became assistant vice-president, operations, and was elected president of the social and athletic association that had been begun by the company in 1933.

Following in his father's footsteps, John Crilly became an expert in his field. He was educated in Elizabeth schools and attended Union Business College and later studied engineering. He held licenses as a steam engineer and as a professional engineer.

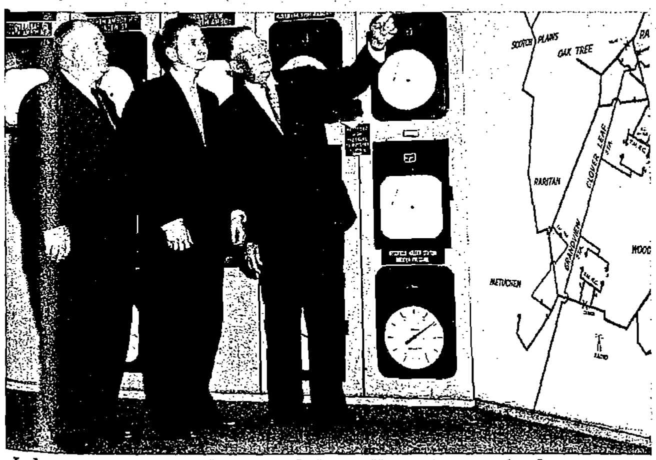
In 1939 a new $80,000 coal conveyor was installed at Erie Street. The conveyor, designed and built to John's specifications, was made of steel and concrete. It was installed to move seventy tons of coke an hour from the railroad cars to the generators. The maximum capacity of the old conveyors had only been thirty-three tons.

In 1941 John was also involved in the design of a new $250,000 generating plant at Erie Street. The addition was expected to boost gas production from 13.5 million to 28.5 million cubic feet.

John was also active in local politics. In 1950 he was nominated for a seat on the board of freeholders. He was appointed to the board of adjustment in 1938 at the recommendation of the mayor, Joseph A. Brophy, and was renamed twice under the next mayor, James T. Kirk.

John Crilly retired from the company in 1961 after fifty-one years. He passed away in Hollywood, Florida, on January 7, 1972.

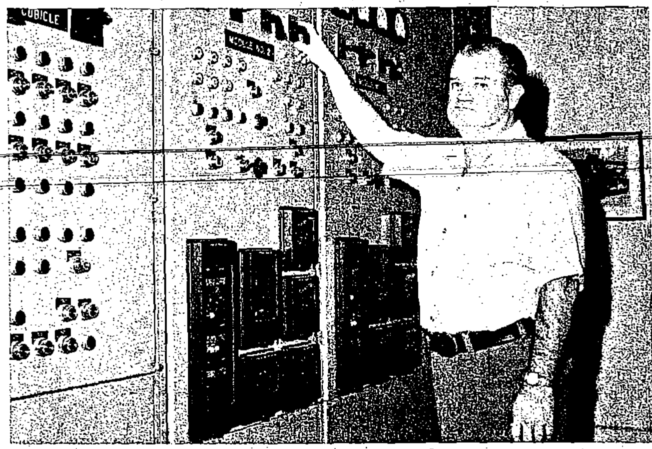
John's brother, Roger Crilly, retired in 1966 after working for the company as division superintendent of Westfield for forty-three-and-a-half years.



John J. Crilly (left) listens while William Potter (right) points out the different conversion districts.

John Crilly had two sons who worked for the company. James A. Crilly was promoted to superintendent, gas production and supply, in November of 1960. The same position had been held by his father for twenty-five years and his grandfather for forty-three years.

Jim, who started with the company in 1945, held several positions at the plant which gave him an excellent background in the operations of the facility. He was responsible for adapting the installation of a remote-control system using high-frequency radio waves to monitor pressure, temperature and other data at five metering points. The company's old telemetering system had been handled by thirty-four telephone wires. The new setup only used a total of nineteen wires.



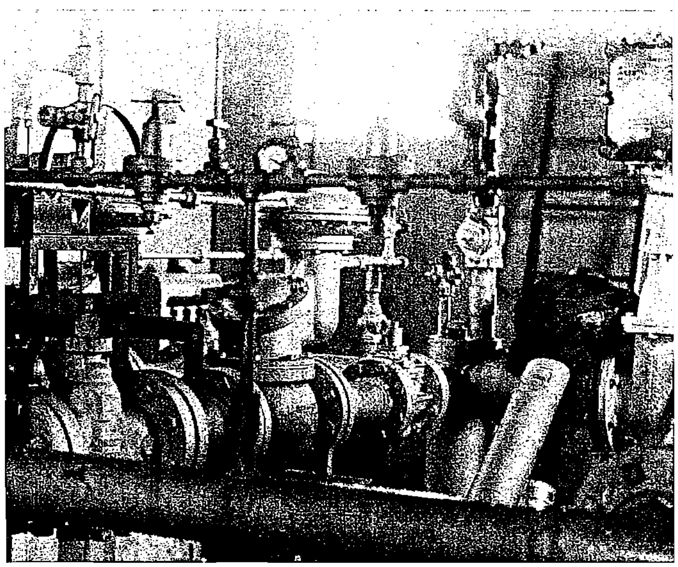
Joe Crilly, Sr. at the controls of the Total Energy system.

John's other son, Joseph P. Crilly, first began working at Erie Street during summer vacations while he was still in high school. But it wasn't until after active service in the merchant marine that Joe joined the company as a works utility man in 1946. Joe inherited from his father a knack for working with pumps and boilers, and after receiving his stationary engineer's license, he was promoted to foreman of the boiler house. In 1959, he became assistant superintendent of shop maintenance, with duties including maintenance and repair work at Erie Street, as well as operation of the steam plant. When the new corporate headquarters building was constructed in 1966, Joe was promoted to manager of the Total Energy plant. He operated and maintained this unique system, which employed jet engines driven by natural gas to produce electricity and steam. Joe retired in 1986. His son, Joseph, Jr., works in the street department in Woodbridge as a crew manager.

This year of 1989 marks the hundredth year of service by the Crilly family to the company.

the demolition of the pipe shop. "Little did we know that Connie Walp, an employee of the gas company, had stored an old Model-T Ford on the second floor. There was so much junk up there you couldn't see the car. Well, they brought the crane in to start the demolition. Stewart Kean drove in just as the crane pulled the wreckage out of the building. Needless to say, he was pretty upset."

The old pump house—the building where the gas was pressurized before being released into the system—was knocked down, and a new one was built in its place. Elizabethtown insulated the new pipes so that the system runs smoothly and quietly. The new pump house is also constructed so that if there is an explosion the building will fall apart like a house of cards to prevent damage to the surrounding community. Other safety factors include electric eyes located around the plant, which detect any flame or heat source and immediately sound an alarm in the control room.



The regulators or "governors" as they were called, which maintained the pressure in the pipes.

In the old pump house the men would put weights on the regulators to maintain pressure in the pipes when the weather was especially cold. If they ran out of lead weights they would improvise. Harry Damm used to come in early in the morning and throw a brick on the gauge so that the line to the Singer plant would stay consistent. At the end of the day he would come back and remove the brick. Barney Walp, assistant superintendent, had a secret store of lead plates, bricks and metal pipes hidden away in case an adjustment was necessary.

In 1941 a new generating plant was built, housing three twelve-foot generators that each had at least 5 million cubic feet of capacity. These new generators were built above ground level so that the ashes would not have to be handled twice in removal. The plant also included a heavy-duty elevator system to be used in case of emergency or equipment failure to lift trucks to the operations floor for dumping into the generators.

The workers at the gas house, as Erie Street was affectionately known, used to name the engines and pumps. Nicknames such as Green Hornet, Black Beauty, Jersey Special, Frog Hollow and Mocking Bird were some of the favorites. The compressors were named for special employees with up to fifty years of service. The five Ingersoll-Rand compressors had brass plaques with the names "Bobbie Burns," "Andy O'Rourke," "Michael Redman," "Roger Crilly" and "Conrad Walp." "Connie" Walp, Barney's father, started employment with the company as a pipe fitter and was promoted to assistant superintendent under John Crilly on January 1, 1937. In October 1959 he became superintendent of gas production, in charge of much of the equipment he had helped to install.

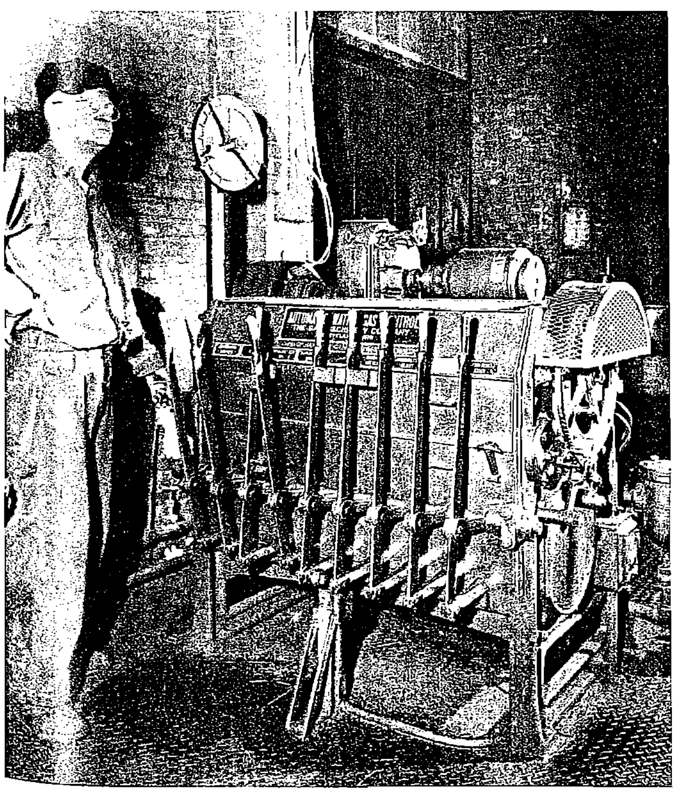
In 1936 there were 105 workers employed at Erie Street. The work was exhausting and the men at Erie Street put in many hours of manual labor. Joe Millhiser, Sr., recalled the winter of 1933-34: "Due to severe frost and cold, the office force did not go home nights, but slept in the building because of the repeated calls to repair broken mains and services. Howard Hickey and I were sleeping next to each other and when I woke up the next morning, both Howard and the cot he had been sleeping on were gone. I found out later that my snoring had driven him away!"

In 1980, bitterly cold weather would again force the men of Erie Street to spend the night at the plant in what has become known as "Christmas at the Gas House." The supply was low, and Frank Bahniuk, who was vice-president of operations and engineering, remembers calling in several employees to decide which part of the system should be shut down. "At the time the peak-shaving propane air plant was being updated and was not ready to be put on-line. We had already shut off service to our interruptible customers. The weathermen were predicting twenty degree weather, but overnight the temperature kept dropping. We were prepared for cold temperatures but not for five-degree weather, and there was simply not enough gas in the system. I was calling everyone I knew trying to locate extra supplies. Finally I remembered that a friend of mine who had been in my wedding party worked at Con Edison. He managed to get fifteen million cubic feet from their LNG plant." Jack MacNaughton was one of the volunteers to come out on Christmas day. As he remembers, "By the time we all got home there wasn't any meat left on the turkey!"

Gas has not been regularly manufactured at the Erie Street plant since March 1951, shortly before the conversion to natural gas was completed. The gas generators were shut down and the whining turbine blowers were silenced. Several old-timers watched wistfully as the last batch of carbureted water gas was manufactured after sixty-two years of operation. The last pump, "Roger Crilly," was turned off as his son, John J. Crilly, stood by.

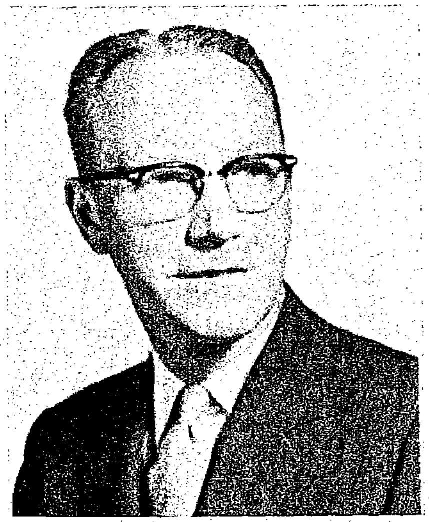
The equipment was converted to produce from coal a gas that equaled the heating value of natural gas, but the system was only used during peak seasons when the demand was very high. Because of the high number of BTUs the storage capacity was double what it had been.

The function of Erie Street changed after the days of manufacturing were over. The control room, where the output of gas was monitored, became the most important function of the plant. In 1952 a new control system was installed. It had taken two years to complete and cost $147,700. Automatic and manual controls were included to assure adequate and continuing supplies. A control board with pressure meters, signal lights and other apparatus could report at a glance the condition of operations at any point in the distribution lines. There were gauges to indicate steam pressure from the engine room as well as boiler feed pressure. In addition, "calorimeters" recorded the heat content of the gas, and new instruments recorded wind pressure and



The gas levers used in the manufacturing process which regulated the flow of gas.

HENRY ROHRS

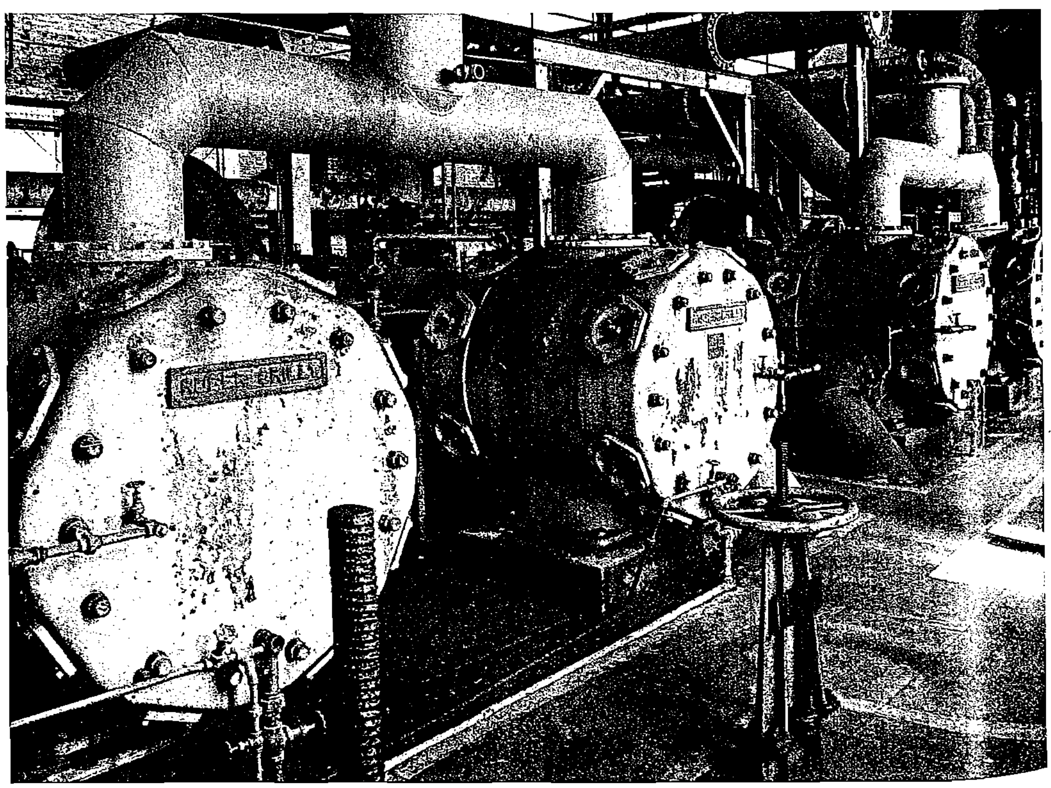


Henry Rohrs as executive vice-president of the company in 1959.

Henry Rohrs graduated from Lehigh University in 1930 with a degree in business administration. He began employment with the company as a house-heat salesman one month after graduation. Two of his classmates and fraternity mates were Townley and Larry Potter, William Potter's sons. When Henry started with the company he lived with the Potter family for a few years. He advanced to house-heat engineer and in 1947 became assistant to the vice-president. In 1949 he became treasurer, than vice-president and treasurer. Mr. Rohrs was quite active in the negotiations with the Federal Power Commission during the conversion to natural gas.

In 1959 he was promoted to executive vice-president and was elected to serve as a director on the board of Elizabethtown Gas in 1963. He directed day-to-day activities at the company and negotiated all gas purchase contracts. This responsibility required long-range planning and detailed studies of gas consumption because contracts were for a minimum period of twenty years. He retired in 1973 after forty-three years of service.

Employees of the gas company gathered at Erie Street to name one of the compressors for Bobbie Burns. Front row from left to right; Henry Crane, Bobbie Burns, Connie Walp, John J. Crilly, Roger Crilly, Francis Engel, Captain John Kean and William Potter, 1945.



The compressor named after Roger Crilly, just prior to the demolition in 1976. The brass plaques were removed and have been saved.

velocity. Bell alarms would go off if the pressure was too high or too low, and lights on the panel would locate the trouble for the operator.

There were 124 employees at the plant in 1951. Not one was laid off due to the introduction of natural gas. Some retired, but many were transferred to other divisions, including the new gate stations where the natural gas was introduced into the lines.

At a party of the Society of Gas Lighting in 1956, a song called "The Gas Lighter's Lament" was composed.

This old industry is changing, many things have come to pass.

Since those pipelines came from Texas, full of clean pure natural gas.

Once we struggled with gum troubles, even argued 'bout which phase.

Now we simply read the meter, these are surely different days.

This Society was founded back in eighteen seventy-five.

And of all the charter members there is not one now alive.

If they knew how things are going, how us poor gas men behave.

They would shed a single silent tear, then turn over in their grave.

CHORUS

Ain't a-gonna need gas men no longer, ain't a-gonna need us guys no more.

Ain't got jobs for gas house foremen, don't need men to sweep the floor.

Don't need men to run the gas sets, or to see the holder fills.

Ain't a-gonna need no men no longer, Univac will post the bills.

In 1955, John J. Crilly was quoted as saying, "Those who made gas used to take a special pride in having it just so, so it would burn with just the right type of blue flame."

The last year in which gas was manufactured was 1966.

During the energy crisis, when natural gas was scarce, the company invested in several alternate fuel sources. In 1974 it installed a propane air plant, which mixes air and propane to produce a gas combustible with natural gas. The project was completed in two steps. First, ten 60,000-gallon tanks were placed on concrete holders. These tanks could be filled to 85 percent of capacity, or 51,000 gallons of propane. To keep the propane at the appropriate temperature the ends of the tanks were of five-and-a-half-inch solid steel and the sides were three-quarter-inch steel.

Second, the company installed storage space for ten railroad tank cars, each with a 30,000-gallon capacity. The new source allowed for an effective natural gas output of 26 million cubic feet of gas for customers for a total of three days.

HARRY AND SOPHIE DAMM

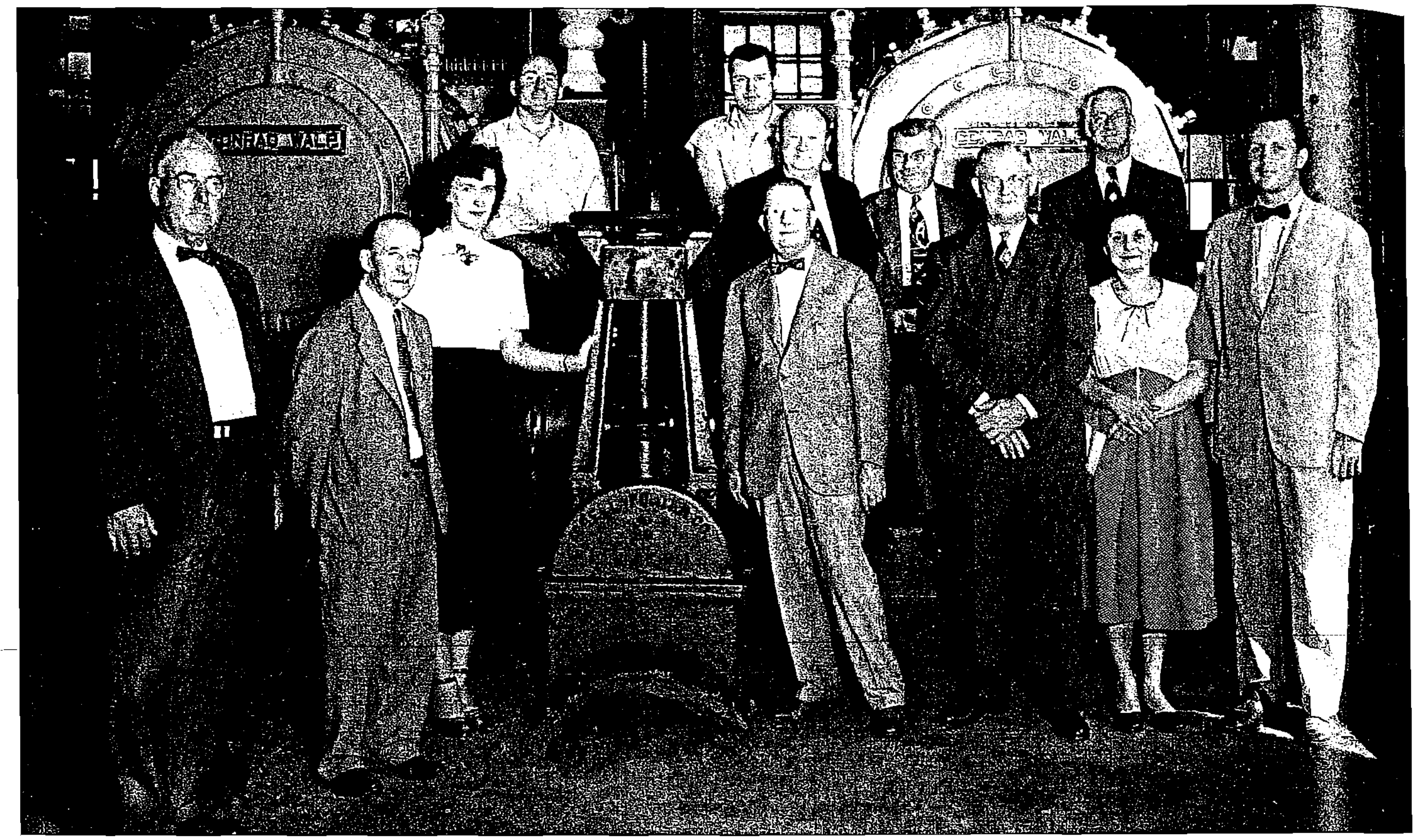
It was no wonder that Harry Damm came to work for the gas company. As a child, he would often look out of his bedroom window and watch all the activity at the Erie Street plant. Trained as a chief machinist's mate in the navy, Harry began his career with the gas company in 1946 as an oiler. "I planned to go back in the navy, but I just loved working with our little 'United Nations' at the gas plant and I never left. We worked fourteen or fifteen hours a day, sometimes weekends and holidays, but there was such great camaraderie. Can you imagine, the neighbors even sent over plates of food to the boys at 'the Gas House' on holidays."

When Harry started with the company, dispatching fifteen million cubic feet of gas in twenty-four hours was considered a big day. By 1965 the amount of processed gas had increased to 96 million cubic feet on a cold day, and by the time he retired 269 million cubic feet was sent out on a peak day.

Harry worked shifts at Erie Street for twenty-one years. During that period he was moved on to steam engineer and finally in 1951, to gas dispatching engineer. His supervisor told him to settle down and get married, so he did. He proposed to the former Sophie Ogozalek, who also worked at Erie Street as a gas production clerk. Because Harry worked shifts, courtship was rather difficult. Their first date was on Columbus Day when they drove to Pennsylvania to see the leaves change. They were married on May 1, 1965.

Sophie ran a one-woman show at Erie Street as senior operations clerk. The Damms had sixty-two years of combined service to the company.

Jack Sharp, general manager of Erie Street said of Harry and Sophie, "They are the epitome of company dedication, always with an easygoing nature and a sense of humor."



On August 4, 1950, one of the compressors was named for Conrad Walp. Present for the ceremony were, left to right, Henry Crane, Bill Aiken, Miss C. Roderick, Barney Walp, Jim Crilly, John J. Crilly, William Potter, Charlie Downey, Connie Walp, Howard Hickey, Viola Gibson, and Bob Kean, Jr.

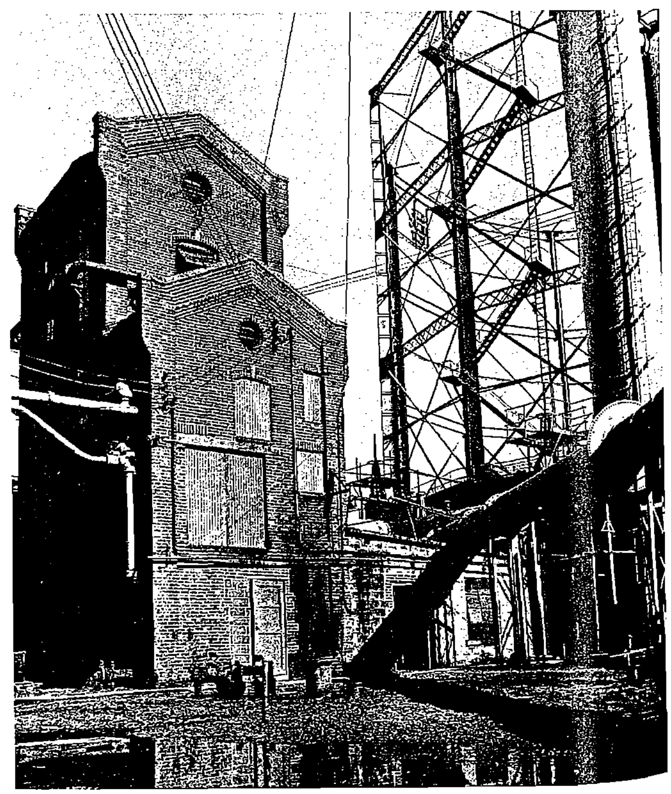
THE GAS HOLDERS

The holders at the Erie Street site were originally constructed to store manufactured gas. In 1923 the company built a holder with a capacity of 3 million cubic feet. Two other tanks had been built earlier, one with a capacity of 1 million cubic feet and the other with a capacity of 340,000 cubic feet. The Number 6 holder, built in 1924, could hold 5 million cubic feet. Number 7 went up in 1929, with a capacity of 6 million cubic feet.

In 1947 construction began on Number 8. Built to hold 10 million cubic feet of gas, it was the largest gas holder in the world.

In the winter when the holders became covered with snow, fifteen to twenty men with two-by-fours would clear the snow off the tops so that the weight would not collapse the holders.

One day in 1948 the men were cleaning the snow off the top of Number 8. In those days there was a top rail but not a bottom rail, and the men worked without any safety lines. Roger "Wick" Crilly lost his balance and slid off the side, grasping the rail at the last moment. Joe Crilly, Sr., tells the outcome of the story. "Roger had the best locker and the men used



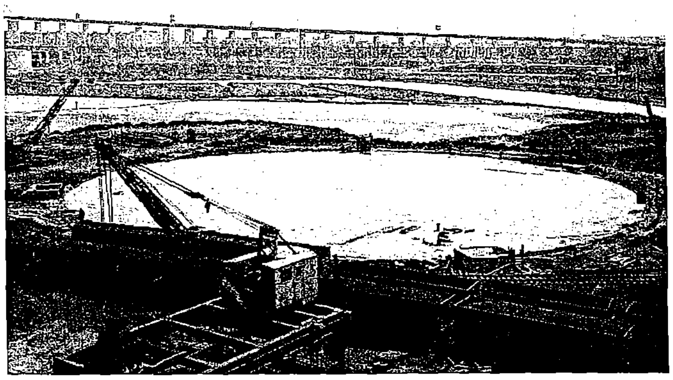
The boiler room just prior to the demolition.

to tease him about it. They say that when Roger was hanging onto the side of Number 8 my brother, Jim, asked if he could have his locker key!"

Great care also had to be exercised to prevent ice from forming in the cups and tanks of the holders. Steam siphons or pushers kept the water used for insulation constantly circulating. During a particularly cold winter one side of the holder kept freezing, and Roger Crilly, Joe, Sr.'s uncle, designed a new siphon, using a burner cock and a mixing chamber from a tank water heater. The new siphon worked on the same principle as the burner on a water heater. The water was drawn into the tube and then forced out at a greater speed. The new siphon remedied the problem and all of the old siphons were eventually replaced.

Neil Schurig tells how all new engineering cadets were indoctrinated into the company by being taken to the top of Number 8. Barney Walp accompanied Neil on his long trip up in the elevator. "The elevator was in need of a new clutch and a brake," recalls Neil. "We stopped short of the top by about five feet and had to climb out onto the top of the holder. Barney said 'Well, do you want to take the elevator down or shall we walk?' I glanced over the side at the forty-foot drop and said 'Thanks. I'll crawl down.' "


Welding the last inch of Number 8, August 17, 1948. Kneeling, John J. Crilly. Standing from left, George "Sharpy" Kleman, Stewart Kean and Captain John Kean.


The foundation of Number 8, May 16, 1947.

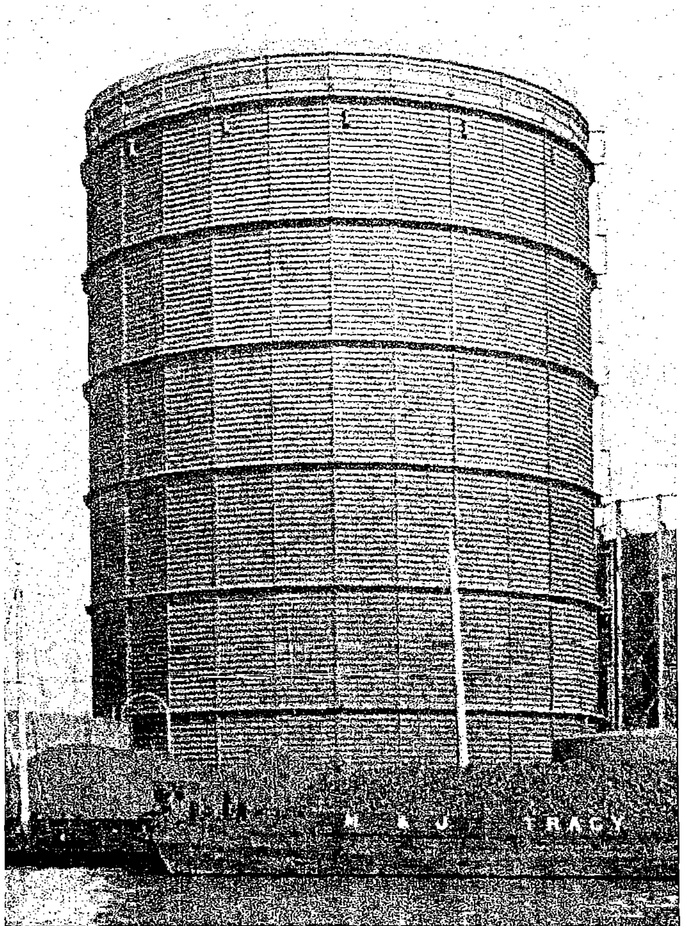
Barney liked to play practical jokes. Apparently he used to lead the young cadets around the Erie Street site with a divining rod made of welding rods, which he claimed would locate buried pipe. The divining rod would part, the men would dig, and to the amazement of the cadets, they would find a pipe. Barney would then turn the divining rod over to the bewildered cadets, and they would set off around the site. For some reason, the contraption would lose its miraculous power. The cadets didn't realize that Barney knew the location of every pipe in the yard and that he could make the rods part at will.

There have been all sorts of stories about objects—including a boat—floating in the holders, but none have been confirmed. One of the holders was converted to hold water to be used as part of the fire protection system at the plant. Joe Crilly remembers swimming in the holder. The men had cut a hole in the side to inspect the inside of the tank. They managed to put a rubber raft through the opening. "Some of the guys just fell off the raft. But we were careful not to venture too far from the opening because it was pretty dark."

In 1982 Elizabethtown commissioned a professional diver to go inside Number 6, which held about 6 million gallons of water. The pressure was not at maximum capacity because something was restricting the flow, so the diver was sent in to take part of the lifts out. He was rigged with a camera when he dived in. The anxious onlookers watched the screen, waiting for "Jaws" to appear. But the inside of the holder was surprisingly clean, except for silt at the bottom. Everyone was disappointed to find the tank empty, with the exception of the diver.

Neil remembers when Number 8 was cleaned out. "It took about forty men to shovel out the muck that had collected in the bottom. They cut a hole in the top of the holder and then in the side so they could pass out the buckets."

On Easter Sunday, 1970, Harry Damm was called out of church with a report that an airplane had hit

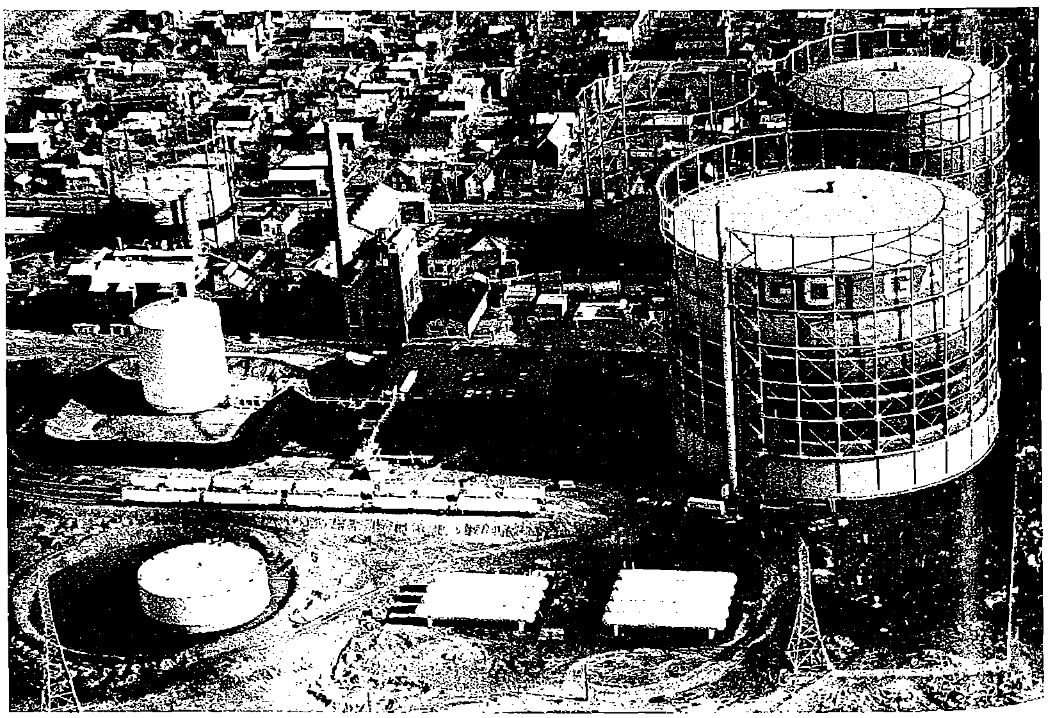


Number 8 as it appeared in the bulletin of the New Jersey Gas Association, 1948.

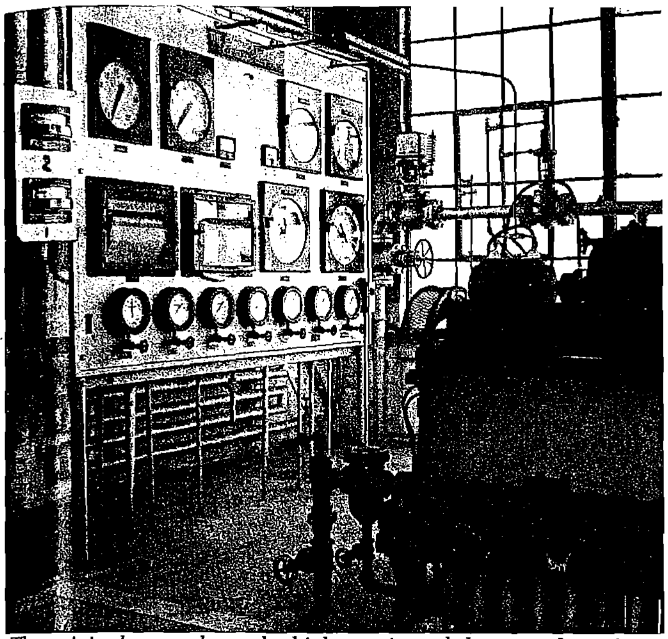
one of the tanks. When he arrived at the yard he found that the airplane had just missed the holders and had pulled several power lines down. Stewart Kean arrived and insisted on getting up on the holders to make sure there wasn't any damage. As Harry recalls, "It was a rainy night and Stewart had trouble getting down. When he finally arrived at the bottom, he said, referring to the men who clean the top, 'Those guys deserve every penny they get!' "

By 1988 only three holders remained and they were emptied because it was no longer cost-effective to maintain them. Even during peaking periods, it is cheaper to convert the more expensive propane and LNG into natural gas than to keep the three holders functioning. It took twenty men to paint the outside of a holder. In the 1950s, Elizabethtown was under contract to buy a certain amount of gas from Transco. If all the gas was not used, the holders stored the excess gas and when they were full they could supply customers with gas for days. Today, because of the increased use of gas for heating and industrial uses, the total capacity of the three holders would only supply consumers for an hour-and-a-half.

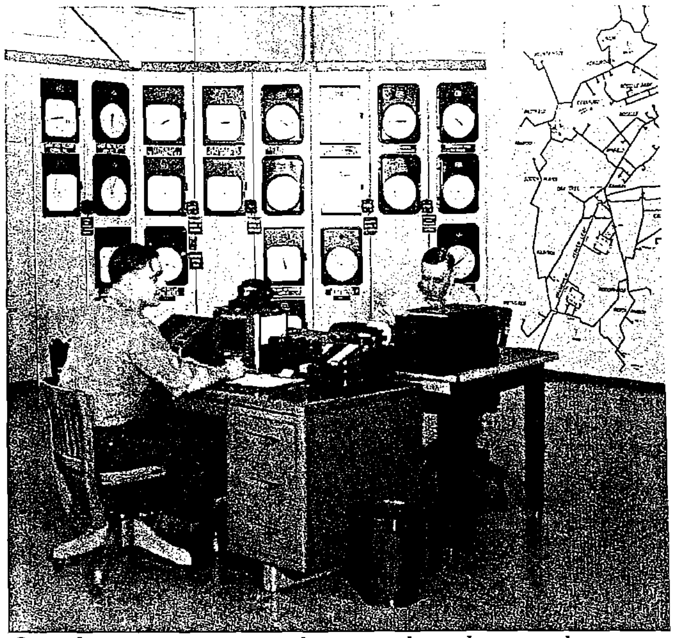
In 1971 the control room was replaced by a new dispatching center. Pete Kassak was on hand for the grand opening. "The dispatching center uses modern computer methodology to scan the output factors at all of our important transfer points every fifteen seconds and makes this information available on a continuous basis, thus eliminating much tedious, time-consuming work."



The Erie Street yard in 1974. (Courtesy of Jack Sharp)



The original control panel which monitored the manufacturing of gas at the Erie Street plant.



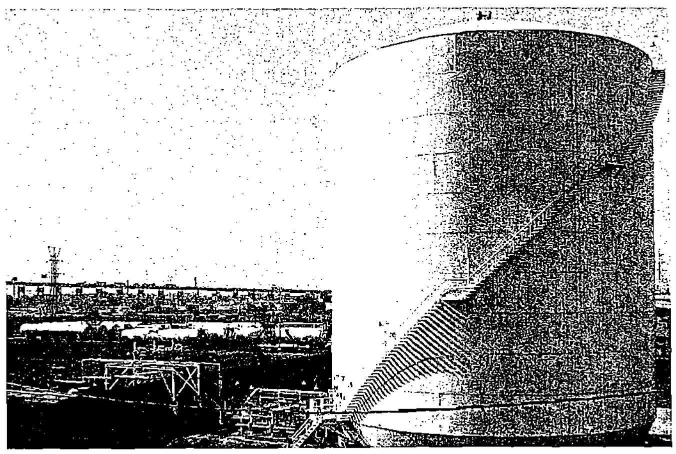
Once the company converted to natural gas the control room became the center of Erie Street. Harry Damm and John Brennan monitor the flow of gas to the gate stations.

The dispatching center computes and logs the quantity of gas sent out to the consumers and controls the entire distribution system for the territories throughout the state. The gas is sent to fifteen gate stations that measure it and reduce pressure for further distribution. This information is fed back to the center, where the progress is monitored. Originally the information was recorded at each panel and an employee walked around to each section to make sight readings. Now the computers scan all parameters every fifteen seconds and store the information. As of 1989 the computers have been upgraded three times.

The busiest times at Erie Street today are during the peaking days. As stated earlier, propane and liquid natural gas (LNG) are kept on the site in case additional gas is needed during cold winter days. Air and a percentage of natural gas are added to the propane before it is ready for distribution. Natural gas is converted to its liquid form by bringing its temperature down to -259 degrees. Once vaporized, one cubic foot of this liquid is equal to 618 cubic feet of gas.

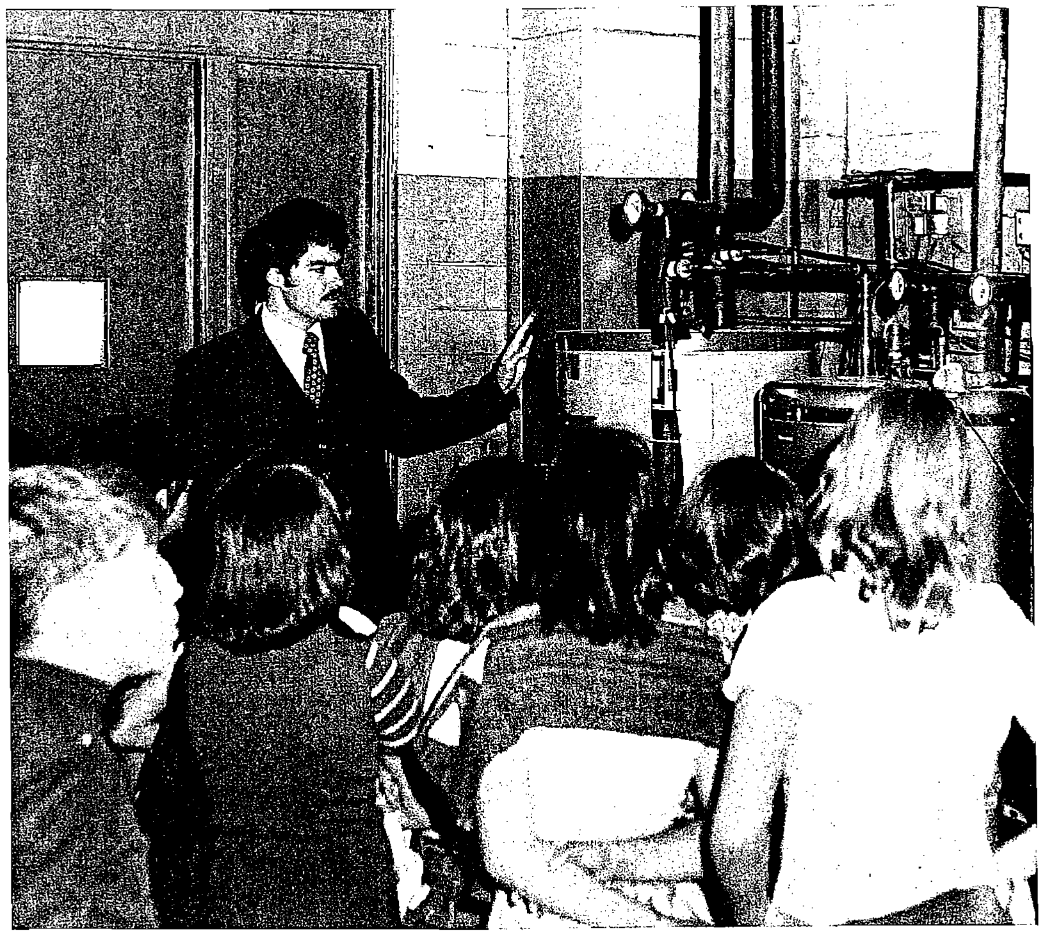
The Elizabeth tank holds a capacity of forty-five thousand barrels of LNG, or the equivalent of 150 million cubic feet of gas. Three gas-fired vaporizers transfer heat to a water bath, which vaporizes the liquid natural gas. As much as thirty-two thousand cubic feet of gas can be vaporized in an hour and can provide a maximum of 30 million cubic feet of gas a day for the system.

A great deal has changed since the days of manufacturing gas. "It was a dusty, dirty place with tar all over the place," said Joe Crilly. But in 1986, when he retired after forty years, "the work was a piece of cake. Not that there isn't still pressure, but the manual labor is gone." The Crillys left their mark on Erie Street when Jim sealed a time capsule, containing items from 1957 collected by John J., into the rafters of Number 7.



The LNG holder and tanks at Erie Street.

But the tradition continues. Harry Damm remembers a ride he took in the elevator with chairman of the board, John Kean. "He asked me how things were at the gas house," Harry recalls. "I said, 'I'm glad to hear you call it the gas house, because everyone else refers to it as the gas control center.' John Kean replied, 'My mother and I will always call it the gas house.' "



Jack Sharp explains to a group of school children how the energy-saving water heaters at Erie Street work.

But the end of the shortage was not yet in sight. Unfortunately, the winter of 1976-1977 proved to be the coldest in sixty years. It was a difficult time for the company but it created a team spirit that would serve it well in the future. Elizabethtown Gas had anticipated the shortage and had backup fuel available. Other gas utilities in the state were not as well-prepared and despite its farsightedness, Elizabethtown found its pipeline deliveries being diverted to make emergency gas available to the other distribution systems.

Duncan Ellsworth, executive vice-president of Elizabethtown, remembers the problems that cold weather brought. "One of the things that people did not realize was that the capacity of the pipelines is greatly affected by how far south the cold air travels. If the cold air comes out of the arctic and hits Washington, D.C., but Atlanta is sixty-five degrees, then you don't have a problem in the northeast. All of the gas supply for New England and the metropolitan area was coming from southern states, like Texas, Oklahoma and Louisiana. None of it was backfeeding from Canada and the north.

"But the winter of '76-'77, the cold spell moved down the eastern seaboard and put a tremendous strain on the entire pipeline system. The cold was so severe in New Orleans and in parts of Texas that the valves froze on some of the wells because they were not frost-free like the ones we have in the north.

"A number of utilities had made no provisions for such a cold winter. New Jersey Natural Gas and South Jersey Gas had insufficient peaking facilities available, so Elizabethtown and Public Service were called upon to help them out with the production from the synthetic natural gas plant."

By the end of January, 1977, Governor Byrne used his emergency powers to place restrictions on all gas users in the state and ordered severe curtailments of industrial plants for one week.

"I remember the day we went down to Trenton to meet with Governor Byrne," Duncan Ellsworth recalled. "It was freezing cold outside and all the presidents of the various utility companies were present. Byrne said, 'Who's got gas and can help us out of this jam?' Public Service agreed to turn on their old oil-gas sets in Harrison and their pipeline gas was made available for New Jersey Natural Gas.

"Of course, New Jersey Natural got the bill for manufacturing the oil-gas, which turned out to be an

The employees at Erie Street in May, 1977.

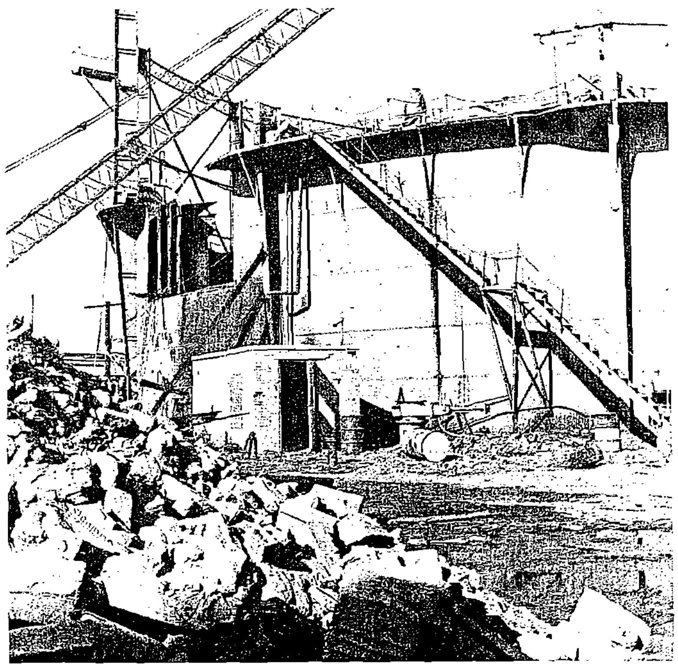
extraordinary $33.00 per thousand cubic feet in contrast to $4.50 for SNG. Under the circumstances no one cared what it cost as long as customers could be supplied with gas."

In addition, the utility companies made a desperate plea to consumers to cut back on fuel use. These pleas had an immediate impact. The highest send-out in January was 190 MMcf, but after repeated news media warnings, usage dropped to 160 MMcf and when the industrial cutback was added, use dropped to 125 MMcf a day.

THE END IN SIGHT

Nineteen seventy-eight did not bring much relief from the shortages and financially it was a disappointing year. Although sales reached record levels, earnings did not keep pace. Taxes and the 28 percent increase of the price of natural gas forced Elizabethtown to file with the Board of Public Utilities for a $16.6 million adjustment in rates, with $6.1 million as an immediate interim increase.

Meanwhile, NUI was beginning to expand its operations. Two new subsidiaries, Lenape Resources and National Enerdrill were added in 1978. Lenape Resources, headed by Cal Carver, was an exploration company formed primarily to concentrate on drilling 150,000 acres the company had under lease in New York State. The results were promising, with ten wells producing an output of 1 billion cubic feet of gas reserves. The finding cost of this gas was considerably less than the reserves discovered by National Exploration, which was in debt for the third year running.



The manufacturing plant at Erie Street was demolished in 1976.

The other subsidiary, National Enerdrill Corporation, was established to own a 50 percent interest in an offshore drilling rig through a joint venture with Noble Drilling Company. The vessel was built by Bethlehem Steel Company and was leased to various oil companies for exploration work on the Gulf Coast. It was a first-of-its-kind prototype and was continuously leased to a major exploration company from the time it was commissioned in 1978 up until the oil crisis of the '80s.

2

NEW JERSEY
DEPARTMENT OF ENVIRONMENTAL PROTECTION AND ENERGY
CN-029
TRENTON, NEW JERSEY 08625

FACT SHEET
FOR NJPDES PERMIT TO DISCHARGE
INTO THE WATERS OF THE STATE OF NEW JERSEY

I. NAMES AND ADDRESSES:

NJPDES APPLICATION NO: NJ0024741

NAME AND ADDRESS OF APPLICANT:

Joint Meeting of Essex and Union Counties
500 South First Street
Elizabeth, New Jersey 07202

City of Elizabeth
50 Winfield Scott Plaza
Elizabeth, New Jersey 07201

NAME AND ADDRESS OF FACILITY:

Joint Meeting Sewage Treatment Plant
500 South First Street
Elizabeth, New Jersey 07202

Please refer to Table III-CSO-1 for the locations and other related information regarding the Combined Sewer Overflow discharge points (CSOs).

Joint Meeting of Essex and Union Counties (Joint Meeting) currently discharges into the designated receiving waters under NJPDES Permit No. NJ0024741. The City of Elizabeth previously discharged from the CSOs under NJPDES Permit No. NJ0020684.

or 20646 ? typo?

II. APPLICABLE STATUTES AND REGULATIONS

The applicable statutes and regulations related to (1) water quality based effluent limitations, (2) required data collection (3) anti-backsliding requirements, and (4) anti-degradation requirements include:

Section 101 of the Federal Clean Water Act prohibits the discharge of toxic pollutants in toxic amounts. The National Policy on toxicity related parameters (Federal Register, dated March 3, 1984) states that toxics control should be achieved through a combination of chemical specific and whole effluent limitations.

Section 301 of the Federal Clean Water Act requires that discharges from POTWs discharge in conformance with the more stringent of secondary treatment or water quality based effluent limitations. In the case of the Joint Meeting Sewage Treatment Plant, the more stringent limitations consist of a combination of secondary treatment, water quality based effluent limitations and performance based effluent limitations. Section 301 also specifically requires that ammonia-N be addressed in all permits. Please refer to Section IV of this Fact Sheet, entitled "Development of Effluent Limitations" for a more complete description of the basis for the effluent limitations. Federal regulations at 40 CFR Part 122.44 require that appropriate effluent limitations be developed for all conventional, non-conventional, and toxic pollutants which cause, have reasonable potential to cause, or contribute to any exceedance or potential exceedance of any applicable water quality criteria or standard. Federal regulations at 40 CFR Part 130.7 require the State to utilize Total Maximum Daily Loads (TMDLs) and Waste Load Allocations (WLAs) in setting water quality based effluent limitations.

Section 303 of the Federal Clean Water Act establishes requirements for water quality standards, including the definitions of those waterbodies that are attaining water quality standards and requirements related to water quality based effluent limitations. Section 303(d) contains requirements related to antibacksliding and antidegradation for water quality based effluent limitations. The requirements related to anti-degradation are detailed at 40 CFR Part 131.12. The State policies concerning the implementation of antidegradation requirements is at N.J.A.C. 7:9-4.5(d). N.J.A.C. 7:14A-3.13(a)12 requires that effluent limitations at least as stringent as those in the previous permit be included in a reissued permit. In accordance with N.J.A.C. 7:15-3.4(i) effluent limitations established as NJPDES permit conditions are considered to be a part of the water quality management plan.

Section 304(l) requires that effluent limitations for dischargers identified on the "short list" be developed for all parameters and that compliance with those final limitations be achieved within three (3) years, but no later than June 4, 1992. However, the United States Environmental Protection Agency (USEPA) has determined that this date may be extended for a period not to exceed three (3) years from the effective date of the final permit issued by the permitting agency containing the Individual Control Strategy (ICS) incorporated as final effluent limitations. For this facility the effective date of the final permit is anticipated to be no later than March 15, 1993. Therefore, the final compliance date has been estimated to be no later than March 15, 1996. The actual effective date of the within a range of quality that shall protect existing/designated uses. The court also stated that before water quality can be diminished in waters whose quality exceeds levels necessary to support designated uses, the Department must make findings that allowing lower water quality is necessary to accommodate important economic or social development. In the Ciba-Geigy matter, existing water quality was determined by reference to the permittee's actual discharge.

Available guidance related to antibacksliding and anti-degradation includes:

USEPA Draft Interim Guidance on Section 402(o), dated 9/29/89

USEPA Region I Antidegradation Guidance, dated 3/23/87

USEPA Region V Antidegradation Guidance, dated 11/10/86 (adopted as National Standard, 11/21/86)

USEPA Region IX Antidegradation Guidance, dated 6/3/87

USEPA Questions and Answers on Antidegradation, dated 8/85 (written prior to 1987 Clean Water Act amendments, so that some information does not apply to the stricter standards of the 1987 amendments)

USEPA Antidegradation, EPA 440/5-88/028, dated 9/88

USEPA Introduction to Water Quality Standards, EPA 440/5-88-089, dated 9/88

USEPA Reference Guide to Water Quality Standards for Indian Tribes, EPA 440/5-90-002, dated 1/90

The Clean Water Enforcement Act (CWEA) requires that effluent limitations be developed for all pollutant parameters discharged in detectable concentration by a POTW which have been established for a permittee discharging into that POTW with an approved pretreatment program. This facility has an approved pretreatment program and some effluent limitations have been determined based on the CWEA.

N.J.A.C. 7:14A-3.14(k) sets the procedures for calculating New Jersey Pollutant Discharge Elimination System (NJPDES) Discharge to Surface Water (DSW) permit conditions in accordance with N.J.A.C. 7:9-5 (Wastewater Discharge Requirements) and/or N.J.A.C. 7:9-4 (Surface Water Quality Standards).

This permit has been prepared in accordance with the National Combined Sewer Overflow Control Strategy (the "National Strategy"). The National Strategy established a uniform, nationally-consistent approach to developing and issuing Nation Pollutant Discharge Elimination System (NPDES) permits for combined sewer overflows (CSOs). The National Strategy applies to EPA and approved NPDES states. CSOs have been shown to have severe adverse impacts on water quality, aquatic biota, and human health under certain conditions. Therefore, the National Strategy specifies that permits for CSOs are to be developed expeditiously to minimize the potential impacts by establishing technology-based and water quality-based requirements of the federal CWA.

CSOs are point source discharges subject to NPDES permit requirements including both technology-based and water quality-based requirements of the federal CWA. Compliance dates for technology-based and water quality-based limitations are governed by the statutory deadlines in Section 301 of the CWA. CSOs that discharge toxic pollutants into water bodies listed under paragraph (B) of Section 304(l) of the CWA are additionally regulated under Section 304(l).

Technology-based permit limits are to be established for best practicable control technology currently available (BPT), best conventional pollutant control technology (BCT), and best available technology economically achievable (BAT) based of best professional judgement (BPJ). The CWA of 1977 mandates compliance with BPT on or before July 1, 1977. The Water Quality Act Amendments of 1987 (WQA) mandates compliance with BCT/BAT on or before March 31, 1989.

The New Jersey Legislature in the enactment of the Sewage Infrastructure Improvement Act (the "Act") (N.J.S.A. 58:25-23 et seq.) declared that combined stormwater and sanitary sewer overflows (CSOs) are a major source of ocean and other surface water pollution, that such sources of pollution are a danger to the public and health and safety of the residents of the State. The Act requires within thirty (30) months after enactment of the Act, any public entity operating a combined stormwater sewer and sanitary sewage system shall provide abatement measures approved by the Department at any CSO point for which a permit is required. Any public entity that fails to provide, in accordance with standards established therefore by the Department, appropriate abatement measures approved by the Department after the expiration of the 30 month period shall be subject to the penalty provisions of P.L. 1977, c. 74 (c.58:10A-1 et seq.). The SIIA was approved and effective on August 3, 1988. The 30 month period expired on February 3, 1991.

The Department has determined that serious problems are associated with dry weather overflows and the discharge of solids/floatables from CSO points. The elimination of dry weather overflows and the control of solids/floatables are correction measures that may be implemented prior to the development of a long-term water quality-based control strategy. This permit includes a performance criteria for the control of solids/floatables and includes language that reaffirms the Department's position on the prohibition of dry weather overflows.

Dry weather overflows from CSO points occur not as a result of any events of precipitation but rather as the result of malfunctioning facilities, illegal connections, etc. Dry weather overflows are raw sewage discharges and are prohibited since they are in direct violation of the Surface Water Quality Standards as specified in N.J.A.C. 7:9-4.1 et seq.

The reduction of solids/floatables from CSOs are a Departmental priority at CSO points. Solids/floatables are presently being discharged directly into the surface waters of the State. The presence of solids/floatables is a violation of State water quality standards in all classifications of surface waters in the State pursuant to N.J.A.C. 7:9-4.1 et seq. "Surface Water Quality Standards"

As previously stated, the National Strategy requires permit strategies bring CSO discharge points into compliance with technology-based requirements of the CWA and applicable State water quality-based standards as expeditiously as possible. This permit has been structured in accordance with a stratagem deemed appropriate to control CSO discharges. Best Management Practices (BMPs) are identified and required to be implemented. A comprehensive monitoring and modeling study is specified to characterize the relationship between CSO discharges and the applicable receiving water's responses for events of precipitation.

In accordance with the National Strategy, this permit has been written as a "system-wide" permit. The CSO discharge points owned and/or operated by the City of Elizabeth, which were previously contained in a separate permit as indicated on page 1 of this Fact Sheet, are proposed to be contained within this permit. A subsequent permit actions will terminate the above referenced permit for the CSO discharges after this permit is issued final.

The use of a system-wide permit does not affect liability. It merely provides a single administrative mechanism for managing all water quality related planning, design and construction activities associated with bringing the CSO discharges into compliance with technology-based requirements of the federal Clean Water Act and state water quality standards. Paragraph I, C of Part III-CSO provides the permittees with an opportunity to delineate their responsibilities with respect to the entire collection, conveyance and treatment facilities.

With respect to the water quality planning, design and construction as well as the operation and maintenance responsibilies associated with the combined sewer systems and the CSOs, as specified in Part III-CSO of this permit, the City of Elizabeth and Joint Meeting are identified as joint permittees. The owners and/or operators of the individual CSO discharge points, and their appurtenances, are responsible for the operation and maintenance requirements and the monitoring and reporting provisions specified in the permit for those discharge points.

A reopener clause is included to facilitate establishment of limitations and the incorporation of existing CSO discharge points appurtenant to the combined sewer system identified during the duration of the permit, after due notice. It is the position of the Department that such a strategy will ensure a consistent, comprehensive, and cost effective mechanism to appropriately control the discharges from CSOs.

III. DESCRIPTION OF FACILITY AND DISCHARGE:

1. Facility Description:

   Treatment consists of coarse bar screening, fine screening, grit settlement/removal, primary settling, aeration of activated sludge, secondary clarification and chlorination. Primary and secondary sludges are combined in gravity thickeners, supplemented by centrifuge thickeners, followed by anaerobic digestion and centrifuge dewatering. The dewatered sludge is shipped, under an interim management contract, for out of state management until a long term sludge management alternative is implemented pursuant to the conditions of JMEUC's Judicial Consent Decree. Sludge is also managed pursuant to permit conditions pertaining to residuals management in Part I-A and Part IV-A of this permit action.

2. Discharge Description:

   a) The treatment plant's effluent is discharged through outfall No. 001 into the Arthur Kill classified as SE-3 waters.

      Latitude: 40° 38' 17"
      Longitude: 74° 11' 51"

      The Permit Summary Table and Limits Derivation Table at the end of this Fact Sheet includes a summary of Joint Meetings DMR data for a time period chosen as representative of Joint Meetings current wastewater treatment operations.

   b) Information concerning the owners, the locations and the descriptions of the CSOs has been included at the end of this Fact Sheet as Table III-CSO-1.

IV. DEVELOPMENT OF EFFLUENT LIMITATIONS:

1. General Methods:

Effluent limitations are developed by three (3) methods:

a. water quality considerations;

b. miscellaneous effluent requirements, such as effluent standards and/or minimum treatment standards;

c. performance based;

Water quality based effluent limits (WQBELs) are used in a permit when it has been determined that more stringent limitations than minimum secondary treatment effluent limitations are required to protect the designated uses of the receiving stream. WQBELs are developed to assure compliance with the New Jersey Surface Water Quality Standards (N.J.A.C. 7:9-4.1 et seq.). In accordance with 40 CFR 122.44, "reasonable potential to cause an excursion above the applicable water quality criteria" has been determined as appropriate from existing effluent data according to the procedures outlined in the USEPA "Technical Support Document for Water Quality Based Toxics Control" (hereinafter the TSD). The 99% confidence interval and 99% probability basis was utilized in this determination. The policies used to develop WQBELs are contained in the standards. Specific procedures and equations are contained in the USEPA documents, "Technical Support Document for Water Quality Based Toxics Control" (EPA-505/2-90-001), and "Permit Writer's Guide to Water Quality Based Permitting for Toxic Pollutants" (EPA-440/4-87-005).

In accordance with N.J.A.C. 7:9-4.6(c)2, water quality based effluent limitations for toxic or toxicity related parameters are developed through a simple mass balance. Effluent limitations for parameters related to dissolved oxygen are developed through a model submitted by the permittee to the Department for evaluation. The Department is aware that limitations for parameters other than those related to dissolved oxygen may be developed through the calibration and verification of a stream/plume model. In accordance with N.J.A.C. 7:9-4.6(c)3, it is the responsibility of the permittee to supply all information necessary to develop water quality based effluent limitations, including a calibrated and verified stream/dilution model as appropriate. Any water quality analysis program to be undertaken by the permittee in support of the calibration and verification of a stream/dilution model must be in accordance with N.J.A.C. 7:9-4.6(c)3 and must be approved by the Department prior to the initiation of any water quality sampling.

In general, the procedure used to develop a WQBEL is to calculate Wasteload Allocations (WLA) that will comply with applicable numeric water quality criteria, determine the effluent quality in terms of Long Term Averages (LTA) that will meet the WLA, and, finally, using the most stringent LTA and treatment system coefficient of variation (CV), calculate average monthly, average weekly, and maximum daily permit limits. For human health criteria, the WLA was set equal to the average monthly limitation and the maximum daily limitation was calculated in accordance with the Technical Support Document. For calculation of the LTA from the WLA, the 99% probability was used (Z = 2.326). For calculation of the average monthly limitation (AML) from the LTA, the 95% probability was used (Z = 1.645). For calculation of the maximum daily limitation (MDL) from the LTA, the 99% probability was used (Z = 2.326). The Technical Support Document previously referenced recommends inclusion of average monthly and daily maximum limitations for all parameters. The Permit Summary and Limit Derivation Table at the end of this Fact Sheet present the appropriate criteria, wasteload allocations, long term averages, and permit limits. The equations used to calculate long term averages and permit limits are listed at the end of this Fact Sheet. The equations are taken from the USEPA documents previously cited.

For discharges into tidal waters, the mixing zone concept is used to develop WLAs. The Department's mixing zone policies are given at N.J.A.C. 7:9-4.5(c)4. The chronic mixing zone specified in the implementation procedures conforms with the definition of the mixing zone given in the Ocean Discharge Criteria (40 CFR Part 125.121(c)). Procedures to implement the mixing zone policies are based on USEPA Technical Support Document previously cited.

The report entitled, "AN EFFLUENT PLUME STUDY TO DETERMINE THE CRITICAL INSTREAM WASTE CONCENTRATION", dated October 1989, and prepared on behalf of Joint Meeting by Lawler, Matusky and Skelly Engineers was used in order to simulate the movement of the effluent discharge. Based on the data projected in the report effluent limitations for applicable pollutants have been calculated in part using an instream waste concentration (IWC) factor of .2 (dilution factor = 5) for the criteria continuous concentration (CCC) of the chronic mixing zone and .67 (dilution factor = 1.5) for the criteria maximum concentration (CMC) of the acute mixing zone.

These values are used to calculate chemical specific limits to comply with water quality criteria for aquatic life protection against acute and chronic toxicity effects. This value is also used to determine the critical Instream Waste Concentration used to calculate the whole effluent toxicity limitations in accordance with N.J.A.C. 7:9-4.6(c)5. The USEPA Technical Support Document recommends that acute criteria be met within 10% of the distance from the edge of the outfall structure to the edge of the regulatory mixing zone.

In accordance with N.J.A.C. 7:9-4.6(c)iii, in the absence of formally promulgated NJDEPE criteria, best available scientific information was used to develop work quality based effluent limits.

In accordance with N.J.A.C. 7:9-4.5(e)7, where water quality based limitations have been determined that are lower than the level of detectability, a reporting level has been included in the permit limitations table. The reporting level is equal to the Minimum Detection Level (MDL) reported at 40 CFR 136 and/or the 1991 USEPA document "Methods for the Chemical Analysis of Water and Wastes".

Miscellaneous effluent limitations are any specific limits or conditions required by federal, state, or local statute or regulation.

Effluent data, taken from the facility's Discharge Monitoring Reports (DMRs), was used in the development of effluent limitations. Individual data points were entered into a computer spreadsheet program for analysis. All data points expressed as "less than" were entered as the numerical equivalent of the detection level indicated in the laboratory report. Data analysis was completed using a log-normal distribution of the data set.

The analysis of the effluent data resulted in one of three possible conditions being proposed in the draft permit:

(1) "MONITOR ONLY" requirements,

(2) water quality based effluent limitations, or

(3) performance based effluent limitations.

The CWEA while requiring the Department to impose limitations, leaves it to the Department's discretion to determine what type of limit to impose. The Department has determined that water quality based limits (WQBEL), since they are related to water quality protection, are preferable limits to impose. However, in certain cases where WQBELS would result in unreasonably large limits, performance based limits are then imposed.

The decision making process for when to propose toxic pollutant effluent limitations for each specific toxic pollutant involved the following procedure when the local agency, such as Joint Meeting, has a delegated industrial pretreatment program:

A. Is there any effluent data for the pollutant?
- NO: "MONITOR ONLY" requirement proposed. Stop.
- YES: Go to B.

B. Is the pollutant discharged in detectable concentrations as defined herein?
- NO: "MONITOR ONLY" requirement proposed. Stop.
- YES: Go to C.

C. Has the pollutant been identified as being limited by the local agency?
- NO: Go to D.
- YES: Go to F.

D. Is there a water quality standard?
- NO: "MONITOR ONLY" requirement proposed. Stop.
- YES: Go to E.

E. Do reasonable potential analysis. Is the result of the reasonable potential analysis defined herein positive?
- NO: "MONITOR ONLY" requirement proposed. Stop.
- YES: Water quality based effluent limitation (WQBEL) proposed. Stop.

F. Is there a water quality standard?
- NO: Performance based effluent limitation calculated as described herein, proposed. Stop.
- YES: Calculated performance based limitation, do reasonable potential analysis and calculated WQBE; go to G.

G. Is the calculated WQBEL less than 20 times the performance based effluent limitation?
- NO: Performance based effluent limitation, calculated as described herein, proposed even if reasonable potential finding is negative. Stop.
- YES: WQBEL proposed even if reasonable potential analysis finding is negative. Stop.

REASONABLE POTENTIAL:
Reasonable potential was determined in accordance with the TSD for all toxic pollutants for which water quality criteria is either being proposed or already exists. The numerically greatest of all the reported detected values for the toxic pollutant or the least stringent reported detection level (whichever was numerically greater) was used in the calculations. If the determination of reasonable potential was inconclusive, then additional effluent monitoring, rather than a WQBEL is proposed.

Due to the requirements of the Clean Water Enforcement Act (CWEA), a positive finding of a reasonable potential analysis is a basis for proposing an effluent limitation. However, a negative finding is not a basis for not proposing an effluent limitation if a pollutant detected in the effluent is limited under the USEPA's Categorical Pretreatment Standards, adopted pursuant to 33 U.S.C. Section 1317, or it was a pollutant for which effluent limitations have been established for a permittee discharging into a municipal treatment works of the delegated local agency.

DETECTABLE CONCENTRATION: A determination of whether a parameter was discharged in detectable concentrations was completed as follows:

a. If the maximum reported value was equal to the average reported value, it was assumed that the parameter has not been detected in any sample.

b. If the maximum reported value was less than five times the method detection level (MDL) specified by the Department in 40 CFR 136 and the 1991 USEPA document "Methods for the Chemical Analysis of Water and Wastes" for the analytical methodology, it was assumed that any variation in reported values was due to variability in reported detection levels and therefore not detected.

c. If the maximum reported value or least stringent reported detection level was greater than five times the detection level specified by the Department in 40 CFR 136 and the 1991 USEPA document "Methods for the Chemical Analysis of Water and Wastes," or no MDL was specified, it was assumed that the parameter was discharged in detectable concentrations subject to item a. above.

PERFORMANCE BASED EFFLUENT LIMITATIONS: The performance based limitations were calculated for each pollutant using the following procedure:

1. Priority pollutant data from the permittee's Discharge Monitoring Reports was examined to determine if the facility is discharging detectable concentrations of any of the priority pollutants.

2. Means, standard deviations, and 95% confidence intervals for individual data points for all parameters where one or more data points indicated that the facility discharges the pollutant in detectable concentrations, were calculated using a lognormal distribution.

3. The upper 95% confidence interval value was used as the monthly effluent mean limitation. Where more than ten data points were available, the upper 95% confidence interval for the Z statistic was used (1.645).

IDENTIFICATION OF POLLUTANTS FOR WHICH LIMITATIONS ARE REQUIRED: The Department sent a letter to the permittee which required identification of all categorical standards appropriate to the permittee's industrial users, local limitations currently contained in the permittee's rules and regulations, as well as any additional pollutants for which the permittee has developed limitations for it's indirect users based upon best professional judgement or any other basis. Based on this information, the list of parameters to be evaluated for CWEA based limitations was developed. The list, along with a copy of the Department's March 10, 1992 letter and a copy of the Joint Meeting's March 26, 1992 response, is attached to the Fact Sheet.

Also, according to the CWEA, the Department is required to place effluent monitoring requirements on those parameters mentioned above for which effluent limitations are not being proposed in this permit.

The permittee was also required to identify those parameters which its treatment facility discharges in detectable concentrations and those parameters which were not discharged in detectable concentrations. As stated in the March 10, 1992 letter, the CWEA allows the Department to exclude those pollutants, if the POTW demonstrates to the Department that the pollutant is not discharged above detectable levels by the POTW. Joint Meeting's response letter, dated March 26, 1992, provided an analysis of which parameters were or were not discharged above detectable levels. Since Joint Meeting's analysis was only based on a single sample, the Department referred to Joint Meeting's effluent data included in the past DMR's reports for a more extensive data set to make a final determination of whether a pollutant was discharged above detectable levels. The variability and lack of sensitivity of the detection levels reported for the available data necessitated the use of the procedure discussed above to determine the detectable concentration.

2. <u>Specific Limitations</u>:

a. <u>BOD_5, TSS, pH, Oil & Grease, Fecal Coliform, % Removal</u>:

BOD_5 and Total Suspended Solids (TSS) limitations for concentration and percent removal are based on the federal definition of secondary treatment. The concentration limitations for BOD_5 and Suspended solids are also consistent with the Interstate Sanitation Commission's (ISC) regulations. The BOD_5 % removal limit is also consistent with N.J.A.C. 7:9-5.8.

pH limitations are based on the Federal definition of secondary treatment found in 40 CFR 133.102(c).

Oil and Grease limitations are based on N.J.A.C. 7:14A-14.

The monthly average and the" 10% of all monthly samples" limitations for fecal coliform are based on N.J.A.C. 7:9-4.14(c)(1)ii(2). These limits as well as the 6 hr. and instantaneous maximum limits are consistent with ISC regulations. The Department will not apply any dilution factor to limitations for indicator parameters related to disease producing organisms. This is due to the potential public health effects of failure to disinfect properly and the fact that bacteria tend to multiply in a receiving waterbody.

Dissolved oxygen is based on N.J.A.C. 7:9-4.14(c).

Effluent loading limitations for BOD_5 and TSS were calculated using a flow of 75 MGD and the appropriate concentration limitations.

b. Toxic Pollutants:

Effluent concentration limitations have been developed in accordance with the Clean Water Enforcement Act and reasonable potential analysis, as described in the previously referenced General Methods section. The criteria for deciding whether or not a limit is imposed for each individual pollutant is summarized in the table entitled "Limits Determination for Delegated Facilities." The specific limitations, along with the appropriate criteria (acute, chronic or human health) have been given in the Limit Derivation and Permit Summary Table of the Fact Sheet. Effluent loading limitations have been calculated using the methods cited above.

c. Chlorine Produced Oxidants:

The effluent limitations for CPO were calculated using an Instream Waste Concentration of .2 for the chronic mixing zone and .67 for the acute mixing zone, based on the dilution study completed by the permittee.

d. Ammonia-N:

Final ammonia-N limitations are performance based limitations. Calculated as previously described in the Fact Sheet, however, the following has been included for your information.

Ammonia-N in Water

Ammonia-N in water exists in two forms: NH_3 and NH_4^+. As NH_3, ammonia-N is called "un-ionized"; as NH_4^+, ammonia-N is called "ionized". Generally, the un-ionized fraction is usually considered more toxic than the ionized fraction. The relative proportion that is found in each fraction is primarily dependent on the temperature and the pH of the solution. At a higher temperature and/or a higher pH, more ammonia-N exists in the un-ionized form as compared to a lower temperature and/or a lower pH. Ammonia-N is usually measured as total ammonia-N, which includes both the ionized and the un-ionized fractions.

The current State water quality standard sets an instream limit on the concentration of un-ionized ammonia that may be allowed in freshwater streams. The water quality criteria can be found at N.J.A.C. 7:9-4.14. However, there is no specific numeric criteria for SE-3 waters. The Department is currently evaluating updated toxicity based criteria for ammonia-N for both saline and fresh waters. This permit may be reopened if necessary to incorporate water quality based limitations after adoption of the updated criteria.

e. <u>Toxicity</u>:

Water quality based acute and chronic whole effluent toxicity limitations were calculated in accordance with the methods at N.J.A.C. 7:9-4.6(c)5. Specifically, the acute toxicity limit was calculated in accordance with N.J.A.C. 7:9-4.6(c)5i and the chronic limit was calculated in accordance with N.J.A.C. 7:9-4.6(c)5iii. Both the acute and chronic limitations were calculated using the Critical Instream Waste Concentration of .2 for the mixing zone determined from the plume model in accordance with N.J.A.C. 7:9-4.6(c)5ii(2).

In calculation of the acute toxicity limitations, N.J.A.C. 7:9-4.6(c)5i allows the use of two application factors. The application factor of 0.05 is used where the toxicity is due to non-persistent substances and the more stringent (i.e. more protective) application factor of 0.01 is used where toxicity is known or suspected to be due to persistent substances. In the calculation of the acute toxicity limit, the Department has conservatively assumed that substances found in the effluent are persistent. Therefore the more stringent application factor of 0.01 was used in the calculation of the acute toxicity limitation.

The calculation of these water quality based toxicity limitations, using the methods cited above, resulted in an acute toxicity limitation of No Measurable Acute Toxicity (NMAT) effluent and a chronic toxicity limitation of an NOEC of 20% effluent (5 TU_c).

The USEPA Technical Support Document previously cited states that "Generally only the more stringent of the acute and chronic toxicity limitation needs to be included in the permit as the final limit since the more stringent limit alone will be fully protective of water quality".

Therefore, the acute and chronic toxicity limitations listed above were compared to determine which one of the two limitations is more protective (i.e. more stringent).

The Department's policy "Interim Policy on Permittees Receiving Chronic Limits" (dated October 4, 1989) outlines the procedures for comparing these limits. Those procedures involve the conversion of both the acute and chronic toxicity limitations to toxic units (TUs) to determine which is more stringent.

As a result of that comparison, it was determined that the chronic toxicity limitation of 20% effluent or 5 TU_c is the more stringent of the calculated acute and chronic water quality based toxicity limitations.

Species selection for chronic testing is based on Best Professional Judgement. Species utilized are those for which an approved USEPA methodology has been developed. Species selection for acute testing is based on N.J.A.C. 7:18-6.6 which requires that the test organism be approved under the regulations governing laboratory certification.

The "Acute Toxicity Biomonitoring Requirements" section has been updated to reflect present standard language and current mailing addresses.

The requirements for the Toxicity Reduction Evaluation are in accordance with N.J.A.C. 7:14A-2.5(a)6 and are included to ensure that immediate action is begun in the event that permit violations were to occur at some future date.

V. <u>ANTIBACKSLIDING / ANTIDEGRADATION ANALYSIS</u>:

In the case of Joint Meeting Sewage Treatment Plant the backsliding and antidegradation issues do not apply. Since the proposed limitations are as stringent as the limitations in the existing permit, the water quality of the receiving stream will be maintained, therefore, there will be no backsliding and an antidegradation analysis is not necessary.

VI. PROCEDURES FOR REQUESTING MODIFICATION OF A WATER QUALITY BASED EFFLUENT LIMITATION:

In accordance with N.J.A.C. 7:14A-9.6(d), application for a modification to water quality based effluent limitations must be made prior to the close of the public comment period. Procedures for requesting a modification to a water quality based effluent limit are found in N.J.A.C. 7:9-4.9 (New Jersey Surface Water Quality Standards). For guidance and/or additional information, please contact the Bureau of Water Quality Analysis, CN-029, Trenton, New Jersey 08625, (609) 633-7020.

VII. PROCEDURES FOR REACHING A FINAL DECISION ON THE DRAFT PERMIT:

These procedures are described in the public notice of preparation of this permit. Included in the public notice are requirements for the submission of comments by a specified date, procedures for requesting a hearing and the nature of the hearing, and other procedures for participation in the final decision.

VIII. DEPE CONTACT:

Additional information concerning the permit may be obtained between the hours of 8:00 A.M. and 4:30 P.M., Monday through Friday from: Mr. John O'Connor at (609) 633-3869.

BASE/NEUTRALS

PARAMETER	LIMIT IMPOSED ON INDUSTRIAL USER	DATA AVAILABLE	DETECTABLE CONCENTRATION	WQ STANDARD	REASONABLE POTENTIAL	WQ LIMIT< 20X PERFORMANCE LIMIT	FINAL * DECISION
Acenaphthene	YES	NO	NO	NO	N/A	N/A	NL
Acenaphthylene	YES	YES	NO	YES	YES	N/A	NL
Anthracene	YES	YES	NO	YES	NO	N/A	NL
Benzidine	YES	YES	NO	YES	YES	N/A	NL
Benzo(a)Anthracene	YES	YES	NO	YES	YES	N/A	NL
Benzo(a)Pyrene	YES	YES	NO	YES	YES	N/A	NL
Benzofluoranthene	YES	YES	NO	YES	YES	N/A	NL
Benzo(ghi)Perylene	YES	YES	NO	YES	YES	N/A	NL
Benzo(k) Fluoranthene	YES	YES	NO	YES	YES	N/A	NL
Bis(2-Chloroethoxy) Methane	YES	YES	NO	NO	N/A	N/A	NL
Bis(2-Chloroethyl) Ether	YES	YES	NO	YES	YES	N/A	NL
Bis(2-Chloroisopropyl) Ether	YES	YES	NO	YES	NO	N/A	NL
Bis(2-Ethylhexyl) Phthalate	YES	YES	YES	YES	YES	YES	WQ
4-Bromophenyl Phenyl Ether	YES	YES	NO	NO	N/A	N/A	NL
Butyl Benzyl Phthalate	YES	YES	NO	YES	NO	N/A	NL
2-Chloronaphthalene	YES	YES	NO	NO	N/A	N/A	NL
4-Chlorophenyl Phenyl Ether	YES	YES	NO	NO	N/A	N/A	NL
Chrysene	YES	YES	NO	YES	YES	N/A	NL
Dibenzo(a,h) Anthracene	YES	YES	NO	YES	YES	N/A	NL
1,2 Dichlorobenzene	YES	YES	NO	YES	NO	N/A	NL
1,3 Dichlorobenzene	YES	YES	NO	YES	NO	N/A	NL
1,4 Dichlorobenzene	YES	YES	NO	YES	NO	N/A	NL
3,3'-Dichlorobenzidine	YES	YES	NO	YES	YES	N/A	NL
Diethyl Phthalate	YES	YES	NO	YES	NO	N/A	NL
Dimethylphthalate	YES	YES	NO	YES	NO	N/A	NL
Di-N-Butylphthalate	YES	YES	YES	YES	NO	NO	PF
2,4 Dinitrotoluene	YES	YES	NO	YES	NO	N/A	NL
2,6 Dinitrotoluene	YES	YES	NO	NO	N/A	N/A	NL
Di-N-Octylphthalate	YES	YES	NO	NO	N/A	N/A	NL
1,2Diphenylhydrazine-as Azobenzene	YES	NO	NO	YES	N/A	N/A	NL
Fluoranthene	YES	YES	NO	YES	NO	N/A	NL
Fluorene	YES	YES	YES	YES	NO	NO	PF
Hexachlorobenzene	YES	YES	NO	YES	YES	N/A	NL
Hexachlorobutadiene	YES	YES	NO	YES	NO	N/A	NL
Hexachlorocyclopentadiene	YES	YES	NO	YES	NO	N/A	NL
Hexachloroethane	YES	YES	NO	YES	NO	N/A	NL
Indeno(1,2,3-cd) Pyrene	YES	YES	NO	YES	YES	N/A	NL
Isophorone	YES	YES	NO	YES	NO	N/A	NL
Naphthalene	YES	YES	NO	NO	N/A	N/A	NL
Nitrobenzene	YES	YES	NO	YES	NO	N/A	NL
N-Nitrosodimethylamine	YES	YES	NO	YES	NO	N/A	NL
N-Nitrosodi-N-Propylamine	YES	YES	NO	NO	N/A	N/A	NL
N-Nitrosodi-N-Butylamine	NO	NO	NO	NO	N/A	N/A	NL
N-Nitrosodiethylamine	NO	NO	NO	NO	N/A	N/A	NL
N-Nitroso-pyrrolindine	NO	NO	NO	NO	N/A	N/A	NL
N-Nitrosodiphenylamine	YES	YES	YES	YES	NO	YES	WQ
Phenanthrene	YES	YES	NO	YES	YES	N/A	NL
Pyrene	YES	YES	NO	YES	NO	N/A	NL
1,2,4-Trichlorobenzene	YES	YES	NO	YES	NO	N/A	NL
1,2,4,5-Tetrachlorobenzene	NO	NO	NO	YES	N/A	N/A	NL
Pentachlorobenzene	NO	NO	NO	YES	N/A	N/A	NL
Polynuclear Aromatic Hydrocarbons	NO	NO	NO	NO	N/A	N/A	NL

* WQ is the water quality based limit, the PF is the performance based limit, and NL is no limit.

PESTICIDES

PARAMETER	LIMIT IMPOSED ON INDUSTRIAL USER	DATA AVAILABLE	DETECTABLE CONCENTRATION	WQ STANDARD	REASONABLE POTENTIAL	WQ LIMIT< 20X PERFORMANCE LIMIT	FINAL * DECISION
Aldrin	YES	YES	NO	YES	YES	N/A	NL
Alpha-BHC	YES	YES	NO	YES	YES	N/A	NL
Beta-BHC	YES	YES	YES	YES	NO	YES	WQ
Gamma-BHC	YES	YES	NO	YES	YES	N/A	NL
Delta-BHC	YES	YES	NO	NO	N/A	N/A	NL
Chlordane	YES	YES	NO	YES	YES	N/A	NL
4,4'-DDT	YES	YES	NO	YES	YES	N/A	NL
4,4'-DDE	YES	YES	NO	YES	YES	N/A	NL
4,4'-DDD	YES	YES	NO	YES	YES	N/A	NL
Dieldrin	YES	YES	NO	YES	YES	N/A	NL
Endosulfan, Total	NO	NO	NO	YES	N/A	N/A	NL
Alpha-Endosulfan	YES	YES	NO	YES	YES	N/A	NL
Beta-Endosulfan	YES	YES	NO	YES	YES	N/A	NL
Endosulfan-Sulfate	YES	YES	NO	YES	NO	N/A	NL
Endrin	YES	YES	NO	YES	YES	N/A	NL
Endrin Aldehyde	YES	NO	NO	YES	N/A	N/A	NL
Heptachlor	YES	YES	NO	YES	YES	N/A	NL
Heptachlor Epoxide	YES	YES	NO	YES	YES	N/A	NL
PCB-1016	YES	YES	NO	NO	N/A	N/A	NL
PCB-1242	YES	YES	NO	NO	N/A	N/A	NL
PCB-1254	YES	YES	NO	NO	N/A	N/A	NL
PCB-1221	YES	YES	NO	NO	N/A	N/A	NL
PCB-1232	YES	YES	NO	NO	N/A	N/A	NL
PCB-1248	YES	YES	NO	NO	N/A	N/A	NL
PCB-1260	YES	YES	NO	NO	N/A	N/A	NL
PCB-Total	NO	NO	NO	NO	N/A	N/A	NL
2,3,7,8Tetrachlorodibenzo-p-dioxin	YES	NO	NO	YES	N/A	N/A	NL
Toxaphene	YES	YES	NO	YES	YES	N/A	NL
Chlorpyrifos	NO	NO	NO	YES	N/A	N/A	NL
Demeton	NO	NO	NO	YES	N/A	N/A	NL
Guthion	NO	NO	NO	YES	N/A	N/A	NL
Malathion	NO	NO	NO	YES	N/A	N/A	NL
Methoxychlor	NO	NO	NO	YES	N/A	N/A	NL
Mirex	NO	NO	NO	YES	N/A	N/A	NL
Parathion	NO	NO	NO	NO	N/A	N/A	NL

METALS

PARAMETER	LIMIT IMPOSED ON INDUSTRIAL USER	DATA AVAILABLE	DETECTABLE CONCENTRATION	WQ STANDARD	REASONABLE POTENTIAL	WQ LIMIT< 20X PERFORMANCE LIMIT	FINAL * DECISION
Aluminum, Total	NO	NO	NO	NO	N/A	N/A	NL
Antimony, Total	YES	YES	NO	YES	NO	N/A	NL
Arsenic, Total	YES	YES	YES	YES	YES	YES	WQ
Barium, Total	NO	NO	NO	NO	N/A	N/A	NL
Beryllium, Total	NO	YES	YES	YES	NO	YES	WQ
Cadmium, Total Recoverable	YES	YES	YES	YES	N/A	YES	WQ
Chromium, Total Recoverable	YES	YES	YES	YES	NO	NO	PF
Cobalt	YES	NO	NO	NO	N/A	N/A	NL
Copper, Total Recoverable	YES	YES	YES	YES	YES	YES	WQ
Cyanide, Total	YES	YES	YES	YES	YES	YES	WQ
Lead, Total Recoverable	YES	YES	YES	YES	YES	YES	WQ

* WQ is the water quality based limit, PF is the performance based limit, and NL is no limit.

ACIDS

PARAMETER	LIMIT IMPOSED ON INDUSTRIAL USER	DATA AVAILABLE	DETECTABLE CONCENTRATION	WQ STANDARD	REASONABLE POTENTIAL	WQ LIMIT< 20X PERFORMANCE LIMIT	FINAL * DECISION
2,4-Dinitrophenol	YES	YES	NO	YES	NO	N/A	NL
2-Nitrophenol	YES	YES	NO	NO	N/A	N/A	NL
4-Nitrophenol	YES	YES	NO	NO	N/A	N/A	NL
Pentachlorophenol	YES	YES	NO	YES	YES	N/A	NL
Phenol	YES	YES	NO	YES	NO	N/A	NL
2,4,6-Trichlorophenol	YES	YES	NO	YES	NO	N/A	NL
2,4,5-Trichlorophenol.	NO	NO	NO	YES	N/A	N/A	NL
Parachlormeta Cresol	YES	NO	NO	NO	N/A	N/A	NL

* WQ is the water quality based limit, PF is the performance based limit, and NL is no limit.

NON CONVENTIONALS

PARAMETER	LIMIT IMPOSED ON INDUSTRIAL USER	DATA AVAILABLE	DETECTABLE CONCENTRATION	WQ STANDARD	REASONABLE POTENTIAL	WQ LIMIT< 20X PERFORMANCE LIMIT	FINAL * DECISION
Chlorine Produced Oxidants	NO	YES	YES	YES	YES	YES	WQ
Ammonia (Total as N)	YES	YES	YES	NO	N/A	N/A	PF
Phosphorus (yellow)	NO	NO	NO	YES	N/A	N/A	NL
Sulfide (hydrogen sulfide)	NO	NO	NO	YES	N/A	N/A	NL

* WQ is the water quality based limit, PF is the performance based limit, and NL is no limit.

The basis for the Proposed Permit Limitations are detailed in the "Development of Effluent Limitations" section of the Fact Sheet.
The effective dates for the Interim and Final Limitations are detailed in Part III-A.

SALINE

LIMITATION DERIVATION and PERMIT SUMMARY TABLE

CONVENTIONALS

All limitations are expressed as maximums unless otherwise noted.

WATER QUALITY LIMITATION DERIVATION								PERMIT SUMMARY			
PARAMETER	CV	WATER QUALITY CRITERIA	WASTE LOAD ALLOC.	LONG TERM AVERAGE		WATER QUALITY LIMITS	WATER QUALITY BASIS	WASTEWATER DATA 05/31/91 through 04/30/92	EXISTING PERMIT LIMITATIONS	PROPOSED PERMIT LIMITATIONS INTERIM	PROPOSED PERMIT LIMITATIONS FINAL
Flow		--	--	--	MONTH AV	--	---	61.2	85	85	85
(MGD)		--	--	--	MAXIMUM	--	---	...	...	...	...
5-Day Biochem. Ox.		--	--	--	MONTH AV	--	---	5273	8519	8516	8516
Demand (kg/d)		--	--	--	WEEKLY AV	--	---	7645	11355	12774	12774
5-Day Biochem. Ox.		--	--	--	MONTH AV	--	---	25	30	30	30
Demand (mg/l)		--	--	--	WEEKLY AV	--	---	32	40(a,b,c)	45(a)	45(a)
Influent 5-Day Bio.		--	--	--	MONTH AV	--	---	MONITOR	MONITOR	MONITOR	MONITOR
Ox. Demand (mg/l)		--	--	--	WEEKLY AV	--	---	ONLY	ONLY	ONLY	ONLY
5-Day Biochem. Ox.		--	--	--	MONTH AV	--	---	87	85	85	85
Demand (min % rem)		--	--	--	FOUR HOUR	--	---	...	85	...	...
Total Suspended		--	--	--	MONTH AV	--	---	3766	8519	8516	8516
Solids (kg/d)		--	--	--	WEEKLY AV	--	---	5291	12779	12774	12774
Total Suspended		--	--	--	MONTH AV	--	---	16	30	30	30
Solids (mg/l)		--	--	--	WEEKLY AV	--	---	22	45(a)	45(a)	45(a)
Influent Total		--	--	--	MONTH AV	--	---	MONITOR	MONITOR	MONITOR	MONITOR
Susp. Sol.(mg/l)		--	--	--	WEEKLY AV	--	---	ONLY	ONLY	ONLY	ONLY
Total Suspended		--	--	--	MONTH AV	--	---	89	85	85	85
Solids (min. % rem)		--	--	--	-------	--	---	...	....	...	...

(a) A maximum concentration of 50 mg/l for BOD_5 & Suspended Solids shall not be exceeded during any (6) hour period.

(b) Maximum average for any four hour period.

(c) Maximum concentration of 45 mg/l for any (7) consecutive days.

LIMITATION DERIVATION and PERMIT SUMMARY TABLE

CONVENTIONALS (CONT'D)

All Limitations are Expressed as Maximums Unless Otherwise Noted.

WATER QUALITY LIMITATION DERIVATION								PERMIT SUMMARY			
PARAMETER	CV	WATER QUALITY CRITERIA	WASTE LOAD ALLOC.	LONG TERM AVERAGE		WATER QUALITY LIMITS	WATER QUALITY BASIS	WASTEWATER DATA 05/31/91 through 04/30/92	EXISTING PERMIT LIMITATIONS	PROPOSED PERMIT LIMITATIONS INTERIM	PROPOSED PERMIT LIMITATIONS FINAL
Fecal Coliform		--	--	--	MONTH AV	--	---	32	200	200	200
(Geo Mean)(#/100mL)		--	--	--	(d)	--	---	86	400	400	400
Dissolved Oxygen		--	--	--	WEEKLY	--	---	7.3	...	MONITOR	MONITOR
(minimum conc.)		--	--	--	MINIMUM	--	---	6.4	4	4	4
Oil and Grease		--	--	--	MONTH AV	--	---	4.3	10	10	10
(mg/l)		--	--	--	MAXIMUM	--	---	8.4	15	15	15
Temperature		--	--	--	MINIMUM	--	---	...	MONITOR	MONITOR	MONITOR
		--	--	--	30 DAY AV	--	---	19.8			
(°C)		--	--	--	MAXIMUM	--	---	...	ONLY	ONLY	ONLY
pH		--	--	--	MINIMUM	--	---	6.6	6	6	6
(su)		--	--	--	MAXIMUM	--	---	7.3	9	9	9

(d) 800 Fecal Coliforms per 100 ml shall not be exceeded as a geometric average during any 6 hour period. No sample may contain more than 2400 Fecal Coliforms per 100 ml.

NON-CONVENTIONALS

All Limitations are Expressed as Maximums Unless Otherwise Noted.

WATER QUALITY LIMITATION DERIVATION									PERMIT SUMMARY			
PARAMETER	CV	WATER QUALITY CRITERIA ACUTE AQUATIC	WATER QUALITY CRITERIA CHRONIC AQUATIC	WASTE LOAD ALLOC.	LONG TERM AVERAGE		WATER QUALITY LIMITS	WATER QUALITY BASIS	WASTEWATER DATA / through /	EXISTING PERMIT LIMITATIONS	PROPOSED PERMIT LIMITATIONS INTERIM	PROPOSED PERMIT LIMITATIONS FINAL
Chlorine Produced	0.6	--	--	--	--	MONTH AV	--	---	(1)	...	MONITOR	2.1 (e)
(Oxidants) (kg/d)		--	--		--	MAXIMUM	--	---	(1)	...	ONLY	5.5 (e)
Chlorine Produced	0.6	13	7.5	--	--	MONTH AV	--	---	(1)	...	MONITOR ONLY	.0074 (e)
(Oxidants)(e)(mg/l)		--	--		--	MAXIMUM	--	---	(1)	2	2	.0195 (e)

(e) The current detection limitation, using an approved test method, is 0.1 mg/l. Therefore, the permittee shall comply with the reporting level of 0.1 mg/l as a daily maximum concentration and 28.4 kg/d as a daily maximum loading until due notice from the Department. Also, the analysis for Chlorine Produced Oxidants should be analyzed by those methods available for Total Residual Chlorine.

LIMITATION DERIVATION and PERMIT SUMMARY TABLE

NON-CONVENTIONALS (CONT'D)

All Limitations are Expressed as Maximums Unless Otherwise Noted.

PARAMETER	CV	WATER QUALITY CRITERIA ACUTE AQUATIC	WATER QUALITY CRITERIA CHRONIC AQUATIC	WASTE LOAD ALLOC.	LONG TERM AVERAGE		WATER QUALITY LIMITS	WATER QUALITY BASIS	WASTEWATER DATA 06/01/91 through 05/31/92	EXISTING PERMIT LIMITATIONS	PROPOSED PERMIT LIMITATIONS INTERIM	PROPOSED PERMIT LIMITATIONS FINAL
Ammonia (Total as N) (kg/d)	0.6	--	--	--	--	MONTH AV	--	---	3407	MONITOR	MONITOR	2782
		--	--	--	--	DAILY MAX	--	---	3066	ONLY	ONLY	7374
Ammonia (Total as N) (mg/l)	0.6	--	--	--	--	MONTH AV	--	---	12	MONITOR	MONITOR	9.8
		--	--	--	--	DAILY MAX	--	---	10.8	ONLY	ONLY	25.8
Phosphorus (yellow) (g/d)	0.6	--	--	--	--	MONTH AV	--	---	(1)	...	MONITOR	MONITOR
		--	--	--	--	DAILY MAX	--	---	(1)	...	ONLY	ONLY
Phosphorus (yellow) (ug/l)	0.6	--	.1	.5	.3	MONTH AV	--	---	(1)	...	MONITOR	MONITOR
		--	--	--	--	DAILY MAX	--	---	(1)	...	ONLY	ONLY
Sulfide (hydrogen-sulfide) (g/d)	0.6	--	2	10	5.3	MONTH AV	--	---	(1)	...	MONITOR	MONITOR
		--	--	--	--	DAILY MAX	--	---	(1)	...	ONLY	ONLY
Sulfide (hydrogen-sulfide) (ug/l)	0.6	--	--	--	--	MONTH AV	--	---	(1)	...	MONITOR	MONITOR
		--	--	--	--	DAILY MAX	--	---	(1)	...	ONLY	ONLY

BIOMONITORING REQUIREMENTS

All Limitations are Expressed as Maximums Unless Otherwise Noted.

PARAMETER	WASTEWATER DATA 05/31/91 through 04/30/92	EXISTING PERMIT LIMITATIONS	PROPOSED PERMIT LIMITATIONS INTERIM	PROPOSED PERMIT LIMITATIONS FINAL
ACUTE BIOMONITORING (LC_{50}) Mysidopsis bahia	96 %	50 %	50 %	...
CHRONIC BIOMONITORING (NOEC) Mysidopsis bahia	23 %	MONITOR ONLY	MONITOR ONLY	20 %

mg/l: milligrams per liter (parts per million)

(1) There is no effluent data for this parameter.
(2) Discharge of this parameter is not authorized by the existing permit.
(3) To be determined.

LIMITATION DERIVATION and PERMIT SUMMARY TABLE

SALINE

BASE/NEUTRALS

All Limitations are Expressed as Maximums Unless Otherwise Noted.

PARAMETER	CV	WATER QUALITY CRITERIA: HUMAN HEALTH PROT. µg/L	WATER QUALITY CRITERIA: AQUATIC LIFE PROTECTION: Acute µg/L	WATER QUALITY CRITERIA: AQUATIC LIFE PROTECTION: Chronic µg/L	WASTE LOAD ALLOC. µg/L	LONG TERM AVG. µg/L	LIMITS: Monthly Average µg/L	LIMITS: Daily Maximum µg/L	BASIS		EFFLUENT DATA 08 / 30 / 89 through 01 / 31 / 91: Load g/day	EFFLUENT DATA: Concentration µg/L	EXISTING PERMIT LIMITATIONS: Load g/day	EXISTING PERMIT LIMITATIONS: Concentration µg/L	DRAFT PERMIT LIMITATIONS: LIMITATION: Load g/day	DRAFT PERMIT LIMITATIONS: LIMITATION: Concentration µg/L	DRAFT PERMIT LIMITATIONS: BASIS (3)
Acenaphthene	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Anthracene	0.6	108000	--	--	540000	347843	540000	1083342	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Acenaphthylene	0.6	0.031	--	--	0.155	0.1	0.155	0.311	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Benzidine	0.6	0.1	--	--	0.5	0.3221	0.5	1.0031	Hum Hlth Cr	DAILY MAX	(1)	80	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	80	(2)	(2)	--	--	
Benzo (a) Anthracene	0.6	0.031	--	--	0.155	0.1	0.155	0.311	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Benzo (a) Pyrene	0.6	0.031	--	--	0.155	0.1	0.155	0.311	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Benzo fluoranthene	0.6	0.031	--	--	0.155	0.1	0.155	0.311	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Benzo (ghi) Perylene	0.6	0.031	--	--	0.155	0.1	0.155	0.311	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Benzo (k) Fluoranthene	0.6	0.033	--	--	0.155	0.1	0.155	0.311	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Bis (2-Chloroethoxy) Methane	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Bis (2-Chloroethyl) Ether	0.6	1.4	--	--	7	4.509	7	14.043	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Bis (2-Chloroisopropyl) Ether	0.6	170000	--	--	850000	547530	850000	1705260	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Bis (2-Ethlyhexyl) Phthalate	0.6	5.92	--	--	29.6	19.067	29.6	59.383	Hum Hlth Cr	DAILY MAX	(1)	180	(2)	(2)	16857	59.383	Hum Hlth Criter
										MONTH AV	(1)	12.8798	(2)	(2)	8402	29.6	
4-Bromophenyl Phenyl Ether	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Butyl Benzyl Phthalate	0.6	416	--	--	2080	1339.84	2080	4172.873	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
2-Chloronaphthalene	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	

LIMITATION DERIVATION and PERMIT SUMMARY TABLE

SALINE

BASE/NEUTRALS

All Limitations are Expressed as Maximums Unless Otherwise Noted.

(WATER QUALITY LIMITATION DERIVATION)										(PERMIT SUMMARY)							
PARAMETER	CV	WATER QUALITY CRITERIA: HUMAN HEALTH PROT. µg/L	WATER QUALITY CRITERIA: AQUATIC LIFE PROTECTION: Acute µg/L	WATER QUALITY CRITERIA: AQUATIC LIFE PROTECTION: Chronic µg/L	WASTE LOAD ALLOC. µg/L	LONG TERM AVG. µg/L	LIMITS: Monthly Average µg/L	LIMITS: Daily Maximum µg/L	BASIS		EFFLUENT DATA 08 / 30 / 89 through 01 / 31 / 91: Load g/day	EFFLUENT DATA: Concentration µg/L	EXISTING PERMIT LIMITATIONS: Load g/day	EXISTING PERMIT LIMITATIONS: Concentration µg/L	DRAFT PERMIT LIMITATIONS: LIMITATION: Load g/day	DRAFT PERMIT LIMITATIONS: LIMITATION: Concentration µg/L	DRAFT PERMIT LIMITATIONS: BASIS (3)
4-Chlorophenyl Phenyl Ether	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Chrysene	0.6	0.031	--	--	0.155	0.1	0.155	0.311	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Dibenzo (a,h) Anthracene	0.6	0.031	--	--	0.155	0.1	0.155	0.311	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
1,2-Dichloro-benzene	0.6	16500	--	--	82500	53142	82500	165510	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
1,3-Dichloro-benzene	0.6	22200	--	--	111000	71501	111000	222687	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
1,4-Dichloro-benzene	0.6	3159	--	--	15795	10174	15795	31687.75	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
3,3'Dichloro-benzidine	0.6	0.0767	--	--	0.384	0.247	0.384	0.769	Hum Hlth Cr	DAILY MAX	(1)	20	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	20	(2)	(2)	--	--	
Diethyl Phthalate	0.6	111000	--	--	555000	357505	555000	1113435	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Dimethyl Phthalate	0.6	2900000	--	--	1.5×10^7	9340228	14500000	29089742	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Di-N-Butyl-phthalate	0.6	15700	--	--	78500	50566	78500	157485.8	Hum Hlth Cr	DAILY MAX	(1)	55	(2)	(2)	12490	44.0	Performanced Based
										MONTH AV	(1)	16.4571	(2)	(2)	6245	22.0	
2,4-Dinitro-toluene	0.6	9.1	--	--	45.5	29.309	45.5	91.282	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
2,6-Dinitro-toluene	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Di-N-Octyl Phthalate	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
1,2-Diphenylhydrazine(as Azobenzene)	0.6	0.541	--	--	2.705	1.742	2.705	5.427	Hum Hlth Cr	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Fluoranthene	0.6	393	--	--	1965	1265.7	1965	3942.162	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Fluorene	0.6	15100	--	--	75500	48633.6	75500	151467.2	Hum Hlth Cr	DAILY MAX	(1)	101	(2)	(2)	6200	21.84	Performanced Based
										MONTH AV	(1)	10.4832	(2)	(2)	3085	10.87	

LIMITATION DERIVATION and PERMIT SUMMARY TABLE

SALINE

BASE/NEUTRALS

All Limitations are Expressed as Maximums Unless Otherwise Noted.

(WATER QUALITY LIMITATION DERIVATION)										(PERMIT SUMMARY)							
PARAMETER	CV	WATER QUALITY CRITERIA: HUMAN HEALTH PROT. µg/L	AQUATIC LIFE PROTECTION: Acute µg/L	AQUATIC LIFE PROTECTION: Chronic µg/L	WASTE LOAD ALLOC. µg/L	LONG TERM AVG. µg/L	LIMITS: Monthly Average µg/L	LIMITS: Daily Maximum µg/L	BASIS		EFFLUENT DATA 08 / 30 / 89 through 01 / 31 / 91: Load g/day	EFFLUENT DATA: Concentration µg/L	EXISTING PERMIT LIMITATIONS: Load g/day	EXISTING PERMIT LIMITATIONS: Concentration µg/L	DRAFT PERMIT LIMITATIONS: LIMITATION Load g/day	DRAFT PERMIT LIMITATIONS: LIMITATION Concentration µg/L	BASIS (3)
Hexachlorobenzene	0.6	0.000775	--	--	0.0039	0.0025	0.0039	0.0078	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Hexachlorobutadiene	0.6	50	--	--	250	161.038	250	501.547	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Hexachlorocyclopentadiene	0.6	17000	--	--	85000	54753	85000	170526	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Hexachloroethane	0.6	12.4	--	--	62	39.938	62	124.384	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Indeno (1,2,3-cd) Pyrene	0.6	0.031	--	--	0.155	0.1	0.155	0.311	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Isophorone	0.6	600	--	--	3000	1932.46	3000	6018.567	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Napthalene	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Nitrobenzene	0.6	1900	--	--	9500	6119.46	9500	19058.79	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
N-Nitrosodimethylamine	0.6	8.1	--	--	40.5	26.088	40.5	81.251	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
N-Nitrosodi-N-Propylamine	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
N-Nitrosodi-N-butylamine	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
N-Nitrosodi-ethylamine	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
N-Nitrosopyrrolidine	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
N-Nitrosodiphenylamine	0.6	16.2	--	--	81	52.176	81	162.501	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	46130	162.5	Hum Hlth Criter
										MONTH AV	(1)	9.33032	(2)	(2)	22993	81	
Phenanthrene	0.6	0.031	--	--	0.155	0.1	0.155	0.311	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
Pyrene	0.6	8970	--	--	44850	28890.2	44850	89977.58	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	

LIMITATION DERIVATION and PERMIT SUMMARY TABLE

SALINE

BASE/NEUTRALS

All Limitations are Expressed as Maximums Unless Otherwise Noted.

PARAMETER	CV	WATER QUALITY CRITERIA: HUMAN HEALTH PROT. µg/L	AQUATIC LIFE PROTECTION: Acute µg/L	AQUATIC LIFE PROTECTION: Chronic µg/L	WASTE LOAD ALLOC. µg/L	LONG TERM AVG. µg/L	LIMITS: Monthly Average µg/L	LIMITS: Daily Maximum µg/L	BASIS		EFFLUENT DATA 08 / 30 / 89 through 01 / 31 / 91: Load g/day	EFFLUENT DATA: Concentration µg/L	EXISTING PERMIT LIMITATIONS: Load g/day	EXISTING PERMIT LIMITATIONS: Concentration µg/L	DRAFT PERMIT LIMITATIONS: LIMITATION Load g/day	DRAFT PERMIT LIMITATIONS: LIMITATION Concentration µg/L	DRAFT PERMIT LIMITATIONS: BASIS (3)
1,2,4-Trichloro-benzene	0.6	113	--	--	565	363.947	565	1133.497	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
1,2,4,5-Tetra-chlorobenzene	0.6	3.25	--	--	16.25	10.467	16.25	32.601	Hum Hlth Cr	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Pentachloro-benzene	0.6	4.21	--	--	21.05	13.559	21.05	42.23	Hum Hlth Cr	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Polynuclear Arom. Hydrocarbons (PAHs)			--	--						DAILY MAX	(1)	--	(2)	(2)	--	--	
										MONTH AV	(1)	--	(2)	(2)	--	--	

LIMITATION DERIVATION and PERMIT SUMMARY TABLE

SALINE

PESTICIDES

All Limitations are Expressed as Maximums Unless Otherwise Noted.

PARAMETER	CV	WATER QUALITY CRITERIA: HUMAN HEALTH PROT. µg/L	AQUATIC LIFE PROTECTION: Acute µg/L	AQUATIC LIFE PROTECTION: Chronic µg/L	WASTE LOAD ALLOC. µg/L	LONG TERM AVG. µg/L	LIMITS: Monthly Average µg/L	LIMITS: Daily Maximum µg/L	BASIS		EFFLUENT DATA 08 / 30 / 89 through 01 / 31 / 91: Load g/day	EFFLUENT DATA: Concentration µg/L	EXISTING PERMIT LIMITATIONS: Load g/day	EXISTING PERMIT LIMITATIONS: Concentration µg/L	DRAFT PERMIT LIMITATIONS: LIMITATION Load g/day	DRAFT PERMIT LIMITATIONS: LIMITATION Concentration µg/L	DRAFT PERMIT LIMITATIONS: BASIS (3)
Aldrin	0.6	0.000144	1.3	--	0.00072	0.00046	0.00072	0.00144	Hum Hlth Cr	DAILY MAX	(1)	0.05	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.05	(2)	(2)	--	--	
Alpha-BHC	0.6	0.0131	--	--	0.066	0.042	0.066	0.131	Hum Hlth Cr	DAILY MAX	(1)	0.05	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.05	(2)	(2)	--	--	
Beta-BHC	0.6	0.46	--	--	2.3	1.482	2.3	4.614	Hum Hlth Cr	DAILY MAX	(1)	0.06	(2)	(2)	1306	4.6	HUMAN HEALTH
										MONTH AV	(1)	0.05091	(2)	(2)	653	2.3	
Gamma-BHC	0.6	0.0625	0.16	0.004	0.02	0.011	0.016	0.033	Chronic Cri	DAILY MAX	(1)	0.05	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.05	(2)	(2)	--	--	
Delta-BHC	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	0.05	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.05	(2)	(2)	--	--	
Chlordane	0.6	0.000283	0.09	0.004	0.00142	0.00091	0.00142	0.00284	Hum Hlth Cr	DAILY MAX	(1)	0.5	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.5	(2)	(2)	--	--	
4,4'-DDT	0.6	0.000591	0.13	0.001	0.00296	0.0019	0.00296	0.00593	Hum Hlth Cr	DAILY MAX	(1)	0.1	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.1	(2)	(2)	--	--	
4,4'-DDE	0.6	0.000591	--	--	0.00296	0.0019	0.00296	0.00593	Hum Hlth Cr	DAILY MAX	(1)	0.1	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.1	(2)	(2)	--	--	
4,4'-DDD	0.6	0.000837	--	--	0.00418	0.0027	0.00418	0.0084	Hum Hlth Cr	DAILY MAX	(1)	0.1	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.1	(2)	(2)	--	--	
Dieldrin	0.6	0.000144	0.71	0.0019	0.00072	0.00046	0.00072	0.00144	Hum Hlth Cr	DAILY MAX	(1)	0.1	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.1	(2)	(2)	--	--	
Endosulfan, Total	0.6	1.99	0.034	0.0087	0.17	0.016	0.025	0.051	Acute Crit	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Alpha-Endosulfan	0.6	--	0.034	0.0087	0.17	0.016	0.025	0.051	Acute Crit	DAILY MAX	(1)	0.05	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.05	(2)	(2)	--	--	
Beta-Endosulfan	0.6	--	0.034	0.0087	0.17	0.016	0.025	0.051	Acute Crit	DAILY MAX	(1)	0.1	(2)	(2)	—	—	MONITOR ONLY
										MONTH AV	(1)	0.1	(2)	(2)			
Endosulfan Sulfate	0.6	2	--	--	10	6.442	10	20.062	Hum Hlth Cr	DAILY MAX	(1)	0.1	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.1	(2)	(2)	--	--	
Endrin	0.6	0.678	0.037	0.0023	0.012	0.006	0.009	0.019	Chronic Cri	DAILY MAX	(1)	0.1	(2)	(2)	—	—	MONITOR ONLY
										MONTH AV	(1)	0.1	(2)	(2)			
Endrin Aldehyde	0.6	0.81	--	--	4.05	2.609	4.05	8.125	Hum Hlth Cr	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	

LIMITATION DERIVATION and PERMIT SUMMARY TABLE
SALINE

PESTICIDES

All Limitations are Expressed as Maximums Unless Otherwise Noted.

PARAMETER	CV	WATER QUALITY CRITERIA: HUMAN HEALTH PROT. µg/L	AQUATIC LIFE PROTECTION: Acute µg/L	AQUATIC LIFE PROTECTION: Chronic µg/L	WASTE LOAD ALLOC. µg/L	LONG TERM AVG. µg/L	LIMITS: Monthly Average µg/L	LIMITS: Daily Maximum µg/L	BASIS		EFFLUENT DATA 08 / 30 / 89 through 01 / 31 / 91: Load g/day	EFFLUENT DATA: Concentration µg/L	EXISTING PERMIT LIMITATIONS: Load g/day	EXISTING PERMIT LIMITATIONS: Concentration µg/L	DRAFT PERMIT LIMITATIONS: LIMITATION Load g/day	DRAFT PERMIT LIMITATIONS: LIMITATION Concentration µg/L	DRAFT PERMIT LIMITATIONS: BASIS (3)
Heptachlor	0.6	0.000214	0.053	0.0036	0.00107	0.00069	0.00107	0.00215	Hum Hlth Cr	DAILY MAX	(1)	0.05	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.05	(2)	(2)	--	--	
Heptachlor Epoxide	0.6	0.000106	0.053	0.0036	0.001	0.0006	0.001	0.001	Hum Hlth Cr	DAILY MAX	(1)	0.05	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.05	(2)	(2)	--	--	
PCB-1016	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	0.5	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.5	(2)	(2)	--	--	
PCB-1242	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	0.5	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.5	(2)	(2)	--	--	
PCB-1254	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	1	(2)	(2)	—	—	MONITOR ONLY
										MONTH AV	(1)	1	(2)	(2)			
PCB-1221	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	0.5	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.5	(2)	(2)	--	--	
PCB-1232	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	0.5	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.5	(2)	(2)	--	--	
PCB-1248	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	0.5	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	0.5	(2)	(2)	--	--	
PCB-1260	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	1	(2)	(2)	—	—	MONITOR ONLY
										MONTH AV	(1)	1	(2)	(2)			
PCB-Total	0.6	0.000247	--	0.03	0.00124	0.0008	0.00124	0.00248	Hum Hlth Cr	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Toxaphene	0.6	0.000747	0.21	0.005	0.00374	0.00241	0.00374	0.00749	Hum Hlth Cr	DAILY MAX	(1)	1	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	1	(2)	(2)	--	--	
2,3,7,8-Tetrachloro-dibenzo-p-dioxin	0.6	1.4×10^{-8}	--	--	7×10^{-8}	5×10^{-8}	7×10^{-8}	1.4×10^{-7}	Hum Hlth Cr	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Chlorpyrifos	0.6	--	0.011	0.0056	0.017	0.005	0.008	0.017	Acute Crit	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Demeton	0.6	--	--	0.1	0.5	0.264	0.409	0.821	Chronic Cri	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Guthion	0.6	--	--	0.01	0.05	0.026	0.041	0.082	Chronic Cri	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Malathion	0.6	--	--	0.1	0.5	0.264	0.409	0.821	Chronic Cri	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	

L I M I T A T I O N D E R I V A T I O N and P E R M I T S U M M A R Y T A B L E
S A L I N E

P E S T I C I D E S

All Limitations are Expressed as Maximums Unless Otherwise Noted.

PARAMETER	CV	(WATER QUALITY LIMITATION DERIVATION) WATER QUALITY CRITERIA: HUMAN HEALTH PROT. µg/L	AQUATIC LIFE PROTECTION: Acute µg/L	AQUATIC LIFE PROTECTION: Chronic µg/L	WASTE LOAD ALLOC. µg/L	LONG TERM AVG. µg/L	LIMITS: Monthly Average µg/L	LIMITS: Daily Maximum µg/L	BASIS	(PERMIT SUMMARY)	EFFLUENT DATA 08 / 30 / 89 through 01 / 31 / 91: Load g/day	EFFLUENT DATA: Concentration µg/L	EXISTING PERMIT LIMITATIONS: Load g/day	EXISTING PERMIT LIMITATIONS: Concentration µg/L	DRAFT PERMIT LIMITATIONS: LIMITATION Load g/day	DRAFT PERMIT LIMITATIONS: LIMITATION Concentration µg/L	DRAFT PERMIT LIMITATIONS: BASIS (3)
Methoxychlor	0.6	--	--	0.03	0.15	0.079	0.123	0.246	Chronic Cri	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Mirex	0.6	--	--	0.001	0.005	0.003	0.004	0.008	Chronic Cri	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Parathion	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	

L I M I T A T I O N D E R I V A T I O N and P E R M I T S U M M A R Y T A B L E
S A L I N E

M E T A L S

All Limitations are Expressed as Maximums Unless Otherwise Noted.

PARAMETER	CV	(WATER QUALITY LIMITATION DERIVATION) WATER QUALITY CRITERIA: HUMAN HEALTH PROT. µg/L	AQUATIC LIFE PROTECTION: Acute µg/L	AQUATIC LIFE PROTECTION: Chronic µg/L	WASTE LOAD ALLOC. µg/L	LONG TERM AVG. µg/L	LIMITS: Monthly Average µg/L	LIMITS: Daily Maximum µg/L	BASIS	(PERMIT SUMMARY)	EFFLUENT DATA 08 / 30 / 89 through 01 / 31 / 91: Load g/day	EFFLUENT DATA: Concentration µg/L	EXISTING PERMIT LIMITATIONS: Load g/day	EXISTING PERMIT LIMITATIONS: Concentration µg/L	DRAFT PERMIT LIMITATIONS: LIMITATION Load g/day	DRAFT PERMIT LIMITATIONS: LIMITATION Concentration µg/L	DRAFT PERMIT LIMITATIONS: BASIS (3)
Aluminum, Total Recoverable	0.6	--	--	--	---	--	---	--	NO CRITERIA	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Antimony, Total	0.6	4300	--	---	21500	13849	21500	43133.1	Hum Hlth Cr	DAILY MAX	(1)	50	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	50	(2)	(2)	--	--	
Arsenic, Total Recoverable	0.6	0.136	69	36	0.7	0.4	0.7	1.4	Hum Hlth Cr	DAILY MAX	(1)	15	(2)	(2)	397	1.4	Hum Hlth Criter
										MONTH AV	(1)	9.9948	(2)	(2)	198	0.7	

LIMITATION DERIVATION and PERMIT SUMMARY TABLE

SALINE-METALS

All Limitations are Expressed as Maximums Unless Otherwise Noted.

PARAMETER	CV	WATER QUALITY CRITERIA: HUMAN HEALTH PROT. µg/L	WATER QUALITY CRITERIA: AQUATIC LIFE PROTECTION Acute µg/L	WATER QUALITY CRITERIA: AQUATIC LIFE PROTECTION Chronic µg/L	WASTE LOAD ALLOC. µg/L	LONG TERM AVG. µg/L	LIMITS Monthly Average µg/L	LIMITS Daily Maximum µg/L	BASIS		EFFLUENT DATA 08 / 30 / 89 through 01 / 31 / 91 Load g/day	EFFLUENT DATA Concentration µg/L	EXISTING PERMIT LIMITATIONS Load g/day	EXISTING PERMIT LIMITATIONS Concentration µg/L	DRAFT PERMIT LIMITATIONS LIMITATION Load g/day	DRAFT PERMIT LIMITATIONS LIMITATION Concentration µg/L	BASIS (3)
Barium, Total	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Beryllium, Total	0.6	0.132	--	--	0.7	0.4	0.7	1.3	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	369	1.3	Hum Hlth Criter
										MONTH AV	(1)	9.43874	(2)	(2)	198	0.7	
Cadmium, Total Recoverable	0.6	169	43	9.3	64.5	20.7	32.2	64.5	Acute Crit	DAILY MAX	(1)	10	(2)	(2)	18310	64.5	Acute Criteria
										MONTH AV	(1)	3.43058	(2)	(2)	9140	32.2	
Chromium, Total Recoverable	0.6	3230	1100	50	250	131.9	204.7	410.7	Chronic Cri	DAILY MAX	(1)	22	(2)	(2)	4542	16.0	Performanced Based
										MONTH AV	(1)	3.12450	(2)	(2)	2271	8.0	
Cobalt	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Copper, Total Recoverable	0.6	--	2.9	2.9	4.4	1.4	2.2	4.4	Acute Crit	DAILY MAX	(1)	34	(2)	(2)	1249	4.4	Acute Criteria
										MONTH AV	(1)	18.3483	(2)	(2)	624	2.2	
Cyanide, Total	0.6	220000	1	1	1.5	0.5	0.7	1.5	Acute Crit	DAILY MAX	(1)	93	(2)	(2)	425	1.5	Acute Criteria
										MONTH AV	(1)	26.3761	(2)	(2)	198	0.7	
Lead, Total Recoverable	0.6	--	220	8.5	42.5	22.4	34.8	69.8	Chronic Cri	DAILY MAX	(1)	66	(2)	(2)	19814	69.8	Chronic Criter.
										MONTH AV	(1)	26.8041	(2)	(2)	9878	34.8	
Manganese	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Mercury, Total Recoverable	0.6	0.146	2.1	0.025	0.125	0.066	0.102	0.205	Chronic Cri	DAILY MAX	(1)	4	(2)	(2)	58.19	0.205	Chronic Criter.
										MONTH AV	(1)	0.25958	(2)	(2)	28.96	0.102	
Molydenum	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Nickel, Total Recoverable	0.6	3900	75	8.3	41.5	21.9	34	68.2	Chronic Cri	DAILY MAX	(1)	59	(2)	(2)	19360	68.2	Chronic Criter.
										MONTH AV	(1)	15.9915	(2)	(2)	9651	34	
Selenium, Total Recoverable	0.6	6800	300	71	355	144.5	224.3	450	Acute Crit	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Silver, Total Recoverable	0.6	65000	2.3	--	3.4	1.1	1.7	3.5	Acute Crit	DAILY MAX	(1)	17	(2)	(2)	993	3.5	Acute Criteria
										MONTH AV	(1)	4.96646	(2)	(2)	482	1.7	
Thallium, Total	0.6	6.22	--	--	31.1	20	31.1	62.4	Hum Hlth Cr	DAILY MAX	(1)	50	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Zinc, Total Recoverable	0.6	--	95	86	142.5	45.8	71	142.5	Acute Crit	DAILY MAX	(1)	210	(2)	(2)	40452	142.5	Acute Criteria
										MONTH AV	(1)	45.0646	(2)	(2)	20155	71	

LIMITATION DERIVATION and PERMIT SUMMARY TABLE

SALINE

VOLATILES

All Limitations are Expressed as Maximums Unless Otherwise Noted.

PARAMETER	CV	WATER QUALITY CRITERIA: HUMAN HEALTH PROT. µg/L	WATER QUALITY CRITERIA: AQUATIC LIFE PROTECTION: Acute µg/L	WATER QUALITY CRITERIA: AQUATIC LIFE PROTECTION: Chronic µg/L	WASTE LOAD ALLOC. µg/L	LONG TERM AVG. µg/L	LIMITS: Monthly Average µg/L	LIMITS: Daily Maximum µg/L	BASIS		EFFLUENT DATA 08 / 30 / 89 through 01 / 31 / 91: Load g/day	EFFLUENT DATA: Concentration µg/L	EXISTING PERMIT LIMITATIONS: Load g/day	EXISTING PERMIT LIMITATIONS: Concentration µg/L	DRAFT PERMIT LIMITATIONS: LIMITATION: Load g/day	DRAFT PERMIT LIMITATIONS: LIMITATION: Concentration µg/L	DRAFT PERMIT LIMITATIONS: BASIS (3)
Acrolein	0.6	780	--	--	3900	2512.2	3900	7824.1	Hum Hlth Cr	DAILY MAX	(1)	12500	(2)	(2)	102195	360.0	Performanced
										MONTH AV	(1)	170.997	(2)	(2)	51097	180.0	Based
Acrylonitrile	0.6	0.665	--	--	3.3	2.1	3.3	6.7	Hum Hlth Cr	DAILY MAX	(1)	12500	(2)	(2)	1901	6.7	Hum Hlth Criter
										MONTH AV	(1)	170.997	(2)	(2)	936	3.3	
Benzene	0.6	71	--	--	355	228.7	355	712.2	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	9084	32.0	Performanced
										MONTH AV	(1)	8.10328	(2)	(2)	4542	16.0	Based
Bromoform	0.6	360	--	--	1800	1159.5	1800	3611.1	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	9084	32.0	Performanced
										MONTH AV	(1)	8.10328	(2)	(2)	4542	16.0	Based
Carbon Tetrachloride	0.6	6.31	--	--	31.5	20.3	31.5	63.3	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	17969	63.3	Hum Hlth Criter
										MONTH AV	(1)	8.10328	(2)	(2)	8942	31.5	
Chlorobenzene	0.6	21000	--	--	105000	67636.1	105000	210649.9	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	9084	32.0	Performanced
										MONTH AV	(1)	8.10328	(2)	(2)	4542	16.0	Based
Chlorodibromo-methane	0.6	34	--	--	170	109.5	170	341.1	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	96829	341.1	Hum Hlth Criter
										MONTH AV	(1)	8.10328	(2)	(2)	48258	170	
Chloroethane	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	1250	(2)	(2)	14194	50.0	Performanced
										MONTH AV	(1)	16.2065	(2)	(2)	7097	25.0	Based
2-Chloroethyl-vinyl Ether	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	1250	(2)	(2)	14194	50.0	Performanced
										MONTH AV	(1)	16.2065	(2)	(2)	7097	25.0	Based
Chloroform	0.6	470	--	--	2350	1513.8	2350	4714.5	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	8516	30.0	Performanced
										MONTH AV	(1)	5.28109	(2)	(2)	4258	15.0	Based
Dichlorobromo-methane	0.6	22	--	--	110	70.9	110	220.7	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	62651	220.7	Hum Hlth Criter
										MONTH AV	(1)	8.10328	(2)	(2)	31226	110	
1,1-Dichloroethane	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	625	(2)	(2)	9084	32.0	Performanced
										MONTH AV	(1)	8.10328	(2)	(2)	4542	16.0	Based
1,2-Dichloroethane	0.6	99	--	--	495	318.9	495	993.1	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	9084	32.0	Performanced
										MONTH AV	(1)	8.25237	(2)	(2)	4542	16.0	Based
1,1-Dichloro-ethene	0.6	3.2	--	--	16	10.3	16	32.1	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	9112	32.1	Hum Hlth Criter
										MONTH AV	(1)	8.10328	(2)	(2)	4542	16	
1,2-Dichlor-propene	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	625	(2)	(2)	9084	32.0	Performanced
										MONTH AV	(1)	8.10328	(2)	(2)	4542	16.0	Based
Cis 1,3-Dichlor-propene	0.6	1700	--	--	8500	5475.3	8500	17052.6	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	9084	32.0	Performanced
										MONTH AV	(1)	8.10328	(2)	(2)	4542	16.0	Based

LIMITATION DERIVATION and PERMIT SUMMARY TABLE

SALINE

VOLATILES

All Limitations are Expressed as Maximums Unless Otherwise Noted.

PARAMETER	CV	WATER QUALITY CRITERIA: HUMAN HEALTH PROT. µg/L	AQUATIC LIFE PROTECTION: Acute µg/L	AQUATIC LIFE PROTECTION: Chronic µg/L	WASTE LOAD ALLOC. µg/L	LONG TERM AVG. µg/L	LIMITS: Monthly Average µg/L	LIMITS: Daily Maximum µg/L	BASIS		EFFLUENT DATA 08 / 30 / 89 through 01 / 31 / 91: Load g/day	EFFLUENT DATA: Concentration µg/L	EXISTING PERMIT LIMITATIONS: Load g/day	EXISTING PERMIT LIMITATIONS: Concentration µg/L	DRAFT PERMIT LIMITATIONS: LIMITATION Load g/day	DRAFT PERMIT LIMITATIONS: LIMITATION Concentration µg/L	DRAFT PERMIT LIMITATIONS: BASIS (3)
trans-1,3-Dichloropropene	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	625	(2)	(2)	9084	32.0	Performanced
										MONTH AV	(1)	8.10328	(2)	(2)	4542	16.0	Based
Ethylbenzene	0.6	27900	--	--	139500	89859.4	139500	279863.4	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	9084	32.0	Performanced
										MONTH AV	(1)	8.10328	(2)	(2)	4542	16.0	Based
Bromomethane	0.6	4000	--	--	20000	12883.1	20000	40123.8	Hum Hlth Cr	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Chloromethane	0.6	470	--	--	2350	1513.8	2350	4714.5	Hum Hlth Cr	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Methylene Chloride	0.6	1600	--	--	8000	5153.2	8000	16049.5	Hum Hlth Cr	DAILY MAX	(1)	70	(2)	(2)	9084	32.0	Performanced
										MONTH AV	(1)	10.4233	(2)	(2)	4542	16.0	Based
1,1,2,2-Tetrachloroethane	0.6	11	--	--	55	35.4	55	110.3	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	31311	110.3	Hum Hlth Criter
										MONTH AV	(1)	8.10328	(2)	(2)	15613	55	
Tetrachloroethene	0.6	4.29	--	--	21.5	13.8	21.5	43	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	12206	43	Hum Hlth Criter
										MONTH AV	(1)	6.41044	(2)	(2)	6103	21.5	
Toluene	0.6	200000	--	--	1000000	644153	1000000	2006189.2	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	9084	32.0	Performanced
										MONTH AV	(1)	8.10328	(2)	(2)	4542	16.0	Based
1,2-Trans-Dichloroethene	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	625	(2)	(2)	9084	32.0	Performanced
										MONTH AV	(1)	8.10328	(2)	(2)	4542	16.0	Based
1,1,1-Trichloroethane	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	625	(2)	(2)	9084	32.0	Performanced
										MONTH AV	(1)	8.10328	(2)	(2)	4542	16.0	Based
1,1,2-Trichloroethane	0.6	42	--	--	210	135.3	210	421.3	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	119596	421.3	Hum Hlth Criter
										MONTH AV	(1)	8.10328	(2)	(2)	59613	210	
Trichloroethene	0.6	81	--	--	405	260.9	405	812.5	Hum Hlth Cr	DAILY MAX	(1)	625	(2)	(2)	9084	32.0	Performanced
										MONTH AV	(1)	8.10328	(2)	(2)	4542	16.0	Based
Vinyl Chloride	0.6	525	--	--	2625	1690.9	2625	5266.2	Hum Hlth Cr	DAILY MAX	(1)	1250	(2)	(2)	14194	50.0	Performanced
										MONTH AV	(1)	16.2065	(2)	(2)	7097	25.0	Based

LIMITATION DERIVATION and PERMIT SUMMARY TABLE

SALINE

ACIDS

All Limitations are Expressed as Maximums Unless Otherwise Noted.

PARAMETER	CV	WATER QUALITY CRITERIA: HUMAN HEALTH PROT. µg/L	WATER QUALITY CRITERIA: AQUATIC LIFE PROTECTION: Acute µg/L	WATER QUALITY CRITERIA: AQUATIC LIFE PROTECTION: Chronic µg/L	WASTE LOAD ALLOC. µg/L	LONG TERM AVG. µg/L	LIMITS: Monthly Average µg/L	LIMITS: Daily Maximum µg/L	BASIS		EFFLUENT DATA 08 / 30 / 89 through 01 / 31 / 91: Load g/day	EFFLUENT DATA: Concentration µg/L	EXISTING PERMIT LIMITATIONS: Load g/day	EXISTING PERMIT LIMITATIONS: Concentration µg/L	DRAFT PERMIT LIMITATIONS: LIMITATION: Load g/day	DRAFT PERMIT LIMITATIONS: LIMITATION: Concentration µg/L	DRAFT PERMIT LIMITATIONS: BASIS (3)
2-Chlorophenol	0.6	402	--	--	2010	1294.7	2010	4032.4	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
4-Chloro-3-methyl-phenol	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
2,4-Dichlorophenol	0.6	794	--	--	3970	2557.3	3970	7964.6	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
2,4-Dimethylphenol	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	10	(2)	(2)	5564	19.8	Performanced
										MONTH AV	(1)	8.86568	(2)	(2)	2776	9.78	Based
4,6-Dinitro-O-Cresol	0.6	765	--	--	3825	2463.9	3825	7673.7	Hum Hlth Cr	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	1	(2)	(2)	--	--	
2,4-Dinitrophenol	0.6	14000	--	--	70000	45090.8	70000	140433.2	Hum Hlth Cr	DAILY MAX	(1)	50	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	50	(2)	(2)	--	--	
2-Nitrophenol	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
4-Nitrophenol	0.6	--	--	--	--	--	--	--	NO CRITERIA	DAILY MAX	(1)	50	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	50	(2)	(2)	--	--	
Pentachlorophenol	0.6	8.2	13	7.9	19.5	6.3	9.7	19.5	Acute Crit	DAILY MAX	(1)	50	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	50	(2)	(2)	--	--	
Phenol	0.6	$4.6x10^6$	--	--	$2.3x10^7$	$1.5x10^7$	$2.3x10^7$	$4.6x10^7$	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
2,4,6-Trichloro-phenol	0.6	6.53	--	--	32.7	21	32.7	65.5	Hum Hlth Cr	DAILY MAX	(1)	10	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	10	(2)	(2)	--	--	
2,4,5-Trichloro-phenol	0.6	9790	--	--	48950	31531.3	48950	98203	Hum Hlth Cr	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	
Parachlorometa cresol	0.6	--	--	--	----	-----	-----	-----	NO CRITERIA	DAILY MAX	(1)	--	(2)	(2)	--	--	MONITOR ONLY
										MONTH AV	(1)	--	(2)	(2)	--	--	

mg/L: milligrams per liter (parts per million) µg/L: micrograms per liter (parts per billion)

(1) There is no effluent data for this parameter.
(2) Discharge of this parameter is not authorized by the existing permit.
(3) See pages 7 through 16 of the Fact Sheet for a detailed discussion of these parameters.

CALCULATION OF LONG TERM AVERAGE

$$LTA = WLA \cdot e^{[(0.5 \cdot \sigma_n^2) - (z \sigma_n)]}$$

$$\sigma_n^2 = \ln [(CV^2/n) + 1]$$

n = 1 (acute criteria)

n = 4 (chronic criteria)

z = 2.326 (99% probability)

CALCULATION OF PERMIT LIMITS

$$\text{Permit Limit} = LTA \cdot e^{[(z \sigma_n) - (0.5 \sigma_n^2)]}$$

$$\sigma_n^2 = \ln [(CV^2/n) + 1]$$

n = number of samples per permit limit averaging period

z = 2.326 for daily maximum limit

z = 1.645 for monthly average limit

State of New Jersey
Department of Environmental Protection and Energy
Environmental Regulation
Wastewater Facilities Regulation Element
CN 029
Trenton, NJ 08625-0029

Scott A. Weiner
Commissioner

Dennis Hart
Administrator

Certified Mail - Return Receipt Requested

MAR 10 1992

Mr. Michael J. Brinker, Executive Director
Joint Meeting of Essex and Union Counties
500 South First Street
Elizabeth, New Jersey 07202

Re: Request for Information NJPDES/DSW No.NJ0024741

Dear Mr. Brinker:

As you are aware, the New Jersey Water Pollution Control Act, (N.J.S.A. 58:10A-7b(3)) directs the Department to include in NJPDES permits issued to POTW's with an approved pretreatment program effluent limits for all pollutants listed under the United States Environmental Protection Agency's Categorical Pretreatment Standards, adopted pursuant to 33 U.S.C., Section 1317, and such other pollutants for which effluent limits have been established for a permittee discharging into said treatment works. The Act further allows the Department to exclude those pollutants identified above if the POTW demonstrates to the Department that the pollutant is not discharged above detectable levels by the POTW.

The Department is currently evaluating the need for toxics limitations for your facility and is therefore requesting that you submit a current list of all categorical standards appropriate to your industrial users, a copy of the local limitations currently contained in your rules and regulations as well as a listing of any additional pollutants for which your facility has developed limitations for indirect user permits based upon best professional judgement or any other basis.

Additionally, your submission should clearly identify and include a rationale with supporting information, for those pollutant parameters that you feel should be excluded from limitation, because you can demonstrate that they are not discharged above detectable levels from your facility. The supporting information should include a comparison of the detection levels used for any chemical specific analyses with the method detection levels listed at 40CFR 136 for the most sensitive appropriate methodology for each parameter.

It is requested that this information be submitted within twenty (20) days of receipt of this letter.

If you have any questions, please contact Nancy Jones of my staff at (609) 633-3869.

Very truly yours,

Jeffrey Reading

Jeffrey Reading, Chief
Bureau of Municipal Discharge Permits
Wastewater Facilities Regulation Program

cc: Pete Lynch, Metro Region
James Murphy, BPR

Joint Meeting of Essex & Union Counties
500 South First Street : Elizabeth : NJ 07202
1-201-353-1313 : FAX: 1-201-353-7925

CM RRR
P 621 387 757

RECEIVED
MAR 31 10 53 AM '92
BUREAU OF MUNICIPAL DISCHARGE PERMITS

March 26, 1992

Mr. Jeffrey Reading
State of New Jersey
Department of Environmental Protection and Energy
Environmental Regulation
Wastewater Facilities Regulation Element
Bureau of Municipal Discharge Permits
CN 029
Trenton, N.J. 08625-0029

Re: NJDEPE's Request for Information

Dear Mr. Reading:

We are in receipt of your letter dated March 10, 1992 requesting information on categorical industrial users, local limitations, and supporting documentation should we desire exclusions for parameters that are not discharged above detectable levels from the treatment plant.

Attached to this letter are the following items:

1) Form AR-4 from the 1992 Annual Pretreatment Report. This form lists the categories in which the Joint Meeting has categorically regulated industrial users. It is our understanding that the Pretreatment element will provide your staff with the regulated parameters for each of the categorical classifications.

2) Data printouts (by month) for the calender year 1991 of the Chemical Specific Parameters for the JMEUC effluent.

Due to the voluminous nature of the printouts, we have included only the data for 1991. Should you require any further back data, please contact us as the data is available.

<u>Parameters To Be Excluded from Limitations</u>

The Joint Meeting is requesting that the following parameters be excluded from requiring effluent limitations due to the data indicating that virtually all samples resulted in "non-detectable"

Joint Meeting of Essex & Union Counties
500 South First Street ◦ Elizabeth ◦ NJ 07202
1-201-353-1313 ◦ FAX: 1-201-353-7925

Parameter	Detection Limit (ug/l)
Arsenic	10
Mercury	2
Antimony	50
Beryllium	10
Selenium	10
Thallium	50
Phenanthrene	10
Pyrene	10
Fluorene	10
Trichlorofluoromethane	10
Methylene Chloride	*
Total Volatiles	5-10
Total Base Neutrals	10
Total Acids	10
Total Pesticides	0.05-0.10

* Please see the information below pertaining to methylene chloride exclusion.

The detection limits for the "Total" organics segments are typical of the majority of the compounds found within that segment. Attached is a copy of the January 1992 report for your perusal of the detection limits.

Please note that we have included Total Volatiles on this list, since the only volatile that has shown up has been methylene chloride (in very minor concentrations). Therefore, should NJDEPE feel the need to monitor volatile organics, it is requested that it be limited to methylene chloride.

In fact, we request that the NJDEPE consider whether there is even a need to work up limits for methylene chloride as many of the samples were either non-detectable, present in "detected but not quantified" concentrations (i.e. below detectable limits), or present in quantities in trace concentrations (very close to the detectable limits).

Should you have any questions or require any further information regarding this matter, please contact Cathy Pullizzi of my staff.

Sincerely,

Michael J. Brinker, Jr.
Executive Director

cc: Cathy Pullizzi, Pretreatment Coordinator
Raymond Papperman, Esq.

1A-PMW
NYTEST ENVIRONMENTAL INC.

VOLATILE ORGANICS ANALYSIS DATA SHEET

SAMPLE MATRIX: WATER
CONC. LEVEL: LOW
ANALYSIS DATE: 1/13/92

SAMPLE ID: 7616
LAB ID: 1090601
DIL FACTOR: 1.00
% MOISTURE: NA

CMPD #	CAS Number	VOLATILE COMPOUNDS	UG/L	
1	74-87-3	Chloromethane	10.0 U.	
2	74-83-9	Bromomethane	10.0 U.	
3	75-01-4	Vinyl Chloride	10.0 U.	NME
4	75-00-3	Chloroethane	10.0 U.	Blank
5	75-09-2	Methylene Chloride	1.0 JB	10 - 1.0 = 0
6	67-64-1	2-Propanone	7.0 JB	7-22 = 0
7	75-15-0	Carbon disulfide	5.0 U.	
8	75-35-4	1,1-Dichloroethene	5.0 U.	
9	75-34-3	1,1-Dichloroethane	5.0 U.	
10	540-59-0	1,2-Dichloroethene (trans)	5.0 U.	
11	67-66-3	Chloroform	2.0 J.	
12	107-06-2	1,2-Dichloroethane	5.0 U.	
13	78-93-3	2-Butanone	10.0 U.	
14	71-55-6	1,1,1-Trichloroethane	5.0 U.	
15	56-23-5	Carbon Tetrachloride	5.0 U.	
16	108-05-4	Vinyl Acetate	10.0 U.	
17	75-27-4	Bromodichloromethane	5.0 U.	
18	78-87-5	1,2-Dichloropropane	5.0 U.	
19	10061-01-5	cis-1,3-Dichloropropene	5.0 U.	
20	79-01-6	Trichloroethene	5.0 U.	
21	124-48-1	Dibromochloromethane	5.0 U.	
22	79-00-5	1,1,2-Trichloroethane	5.0 U.	5.0
23	71-43-2	Benzene	5.0 U.	
24	10061-02-6	Trans-1,3-Dichloropropene	5.0 U.	
25	75-25-2	Bromoform	5.0 U.	
26	108-10-1	4-Methyl-2-Pentanone	10.0 U.	
27	591-78-6	2-Hexanone	10.0 U.	
28	127-18-4	Tetrachloroethene	5.0 U.	
29	79-34-5	1,1,2,2-Tetrachloroethane	5.0 U.	
30	108-88-3	Toluene	5.0 U.	
31	108-90-7	Chlorobenzene	5.0 U.	For Total 0.5 ug/L
32	100-41-4	Ethylbenzene	5.0 U.	
33	100-42-5	Styrene	5.0 U.	
34	1330-20-7	Xylene (total)	5.0 U.	
35	107-02-8	Acrolein	100.0 U.	
36	107-13-1	Acrylonitrile	100.0 U.	
37	110-75-8	2-Chloroethylvinylether	10.0 U.	
38		Dichlorodifluoromethane	10.0 U.	
39		Dichlorobenzene (total)	30.0 U.	
40		Trichlorofluoromethane	10.0 U.	
41				

1B-PMW

NYTEST ENVIRONMENTAL INC.

SEMIVOLATILE ORGANICS ANALYSIS DATA SHEET

SAMPLE MATRIX: WATER
CONC. LEVEL: LOW
EXTRACTION DATE: 1/6/92
ANALYSIS DATE: 1/23/92

SAMPLE ID: 7616
LAB ID: 1090601
DIL FACTOR: 1.00
% MOISTURE: NA

CMPD #	CAS Number	BASE NEUTRAL COMPOUNDS	UG/L
1	111-44-4	bis(2-Chloroethyl)ether	10.0 U.
2	541-73-1	1,3-Dichlorobenzene	10.0 U.
3	106-46-7	1,4-Dichlorobenzene	10.0 U.
4	95-50-1	1,2-Dichlorobenzene	10.0 U.
5	108-60-1	bis(2-chloroisopropyl)ether	10.0 U.
6	621-64-7	N-Nitroso-Di-n-Propylamine	10.0 U.
7	67-72-1	Hexachloroethane	10.0 U.
8	98-95-3	Nitrobenzene	10.0 U.
9	78-59-1	Isophorone	10.0 U.
10	111-91-1	bis(2-chloroethoxy)Methane	10.0 U.
11	120-82-1	1,2,4-Trichlorobenzene	10.0 U.
12	106-47-8	4-Chloroaniline	10.0 U.
13	87-68-3	Hexachlorobutadiene	10.0 U.
14	91-57-6	2-Methylnaphthalene	10.0 U.
15	77-47-4	Hexachlorocyclopentadiene	10.0 U.
16	91-58-7	2-Chloronaphthalene	10.0 U.
17	88-74-4	2-Nitroaniline	50.0 U.
18	131-11-3	Dimethyl Phthalate	10.0 U.
19	99-09-2	3-Nitroaniline	50.0 U.
20	132-64-9	Dibenzofuran	10.0 U.
21	121-14-2	2,4-Dinitrotoluene	10.0 U.
22	606-20-2	2,6-Dinitrotoluene	10.0 U.
23	84-66-2	Diethylphthalate	10.0 U.
24	7005-72-3	4-Chlorophenyl-phenylether	10.0 U.
25	100-01-6	4-Nitroaniline	50.0 U.
26	86-30-6	N-Nitrosodiphenylamine	10.0 U.
27	101-55-3	4-Bromophenyl-phenylether	10.0 U.
28	118-74-1	Hexachlorobenzene	10.0 U.
29	84-74-2	Di-n-Butylphthalate	10.0 U.
30	85-68-7	Butylbenzylphthalate	10.0 U.
31	91-94-1	3,3'-Dichlorobenzidine	20.0 U.
32	117-81-7	bis(2-Ethylhexyl)Phthalate	1.0 J.
33	117-84-0	Di-n-Octyl Phthalate	10.0 U.
34	62-75-9	N-Nitrosodimethylamine	10.0 U.
35	62-53-3	Aniline	10.0 U.
36	92-87-5	Benzidine	80.0 U.
37		Dioxin (Screen)	ND
38		1,2-Diphenylhydrazine	10.0 U.
39			
40			
41			

Total BN = <80

CMPD #	CAS Number	BASE NEUTRAL/PAH COMPOUNDS	UG/L
42	91-20-3	Naphthalene	10.0 U.
43	208-96-8	Acenaphthylene	10.0 U.
44	83-32-9	Acenaphthene	10.0 U.
45	86-73-7	Fluorene	10.0 U.
46	85-01-8	Phenanthrene	10.0 U.
47	120-12-7	Anthracene	10.0 U.
48	206-44-0	Fluoranthene	10.0 U.
49	129-00-0	Pyrene	10.0 U.
50	56-55-3	Benzo(a)Anthracene	10.0 U.
51	218-01-9	Chrysene	10.0 U.
52	205-99-2	Benzo(b)Fluoranthene	10.0 U.
53	207-08-9	Benzo(k)Fluoranthene	10.0 U.
54	50-32-8	Benzo(a)Pyrene	10.0 U.
55	193-39-5	Indeno(1,2,3-cd)Pyrene	10.0 U.
56	53-70-3	Dibenz(a,h)Anthracene	10.0 U.
57	191-24-2	Benzo(g,h,i)Perylene	10.0 U.
58			
59			
60			
		ACID COMPOUNDS	
61	108-95-2	Phenol	10.0 U.
62	95-57-8	2-Chlorophenol	10.0 U.
63	100-51-6	Benzyl Alcohol	10.0 U.
64	95-48-7	2-Methylphenol	10.0 U.
65	106-44-5	4-Methylphenol	10.0 U.
66	88-75-5	2-Nitrophenol	10.0 U.
67	105-67-9	2,4-Dimethylphenol	10.0 U.
68	65-85-0	Benzoic Acid	3.0 J.
69	120-83-2	2,4-Dichlorophenol	10.0 U.
70	59-50-7	4-Chloro-3-Methylphenol	10.0 U.
71	88-06-2	2,4,6-Trichlorophenol	10.0 U.
72	95-95-4	2,4,5-Trichlorophenol	50.0 U.
73	51-28-5	2,4-Dinitrophenol	50.0 U.
74	100-02-7	4-Nitrophenol	50.0 U.
75	534-52-1	4,6-Dinitro-2-Methylphenol	50.0 U.
76	87-86-5	Pentachlorophenol	50.0 U.
77			
78			
79			
80			

Total Acid = 1.5

1 D-T

NYTEST ENVIRONMENTAL INC.

TCL PESTICIDE/PCB ORGANICS ANALYSIS DATA SHEET

SAMPLE MATRIX: WATER
CONC. LEVEL: LOW
EXTRACTION DATE: 1/7/92
ANALYSIS DATE: 1/29/92

SAMPLE ID: 7616
LAB SAMPLE ID: 1090601
DIL FACTOR: 1.00
% MOISTURE: NA

CMPD #	CAS Number	PESTICIDE/PCB COMPOUND	UG/L
1	319-84-6	Alpha-BHC	0.050 U.
2	319-85-7	Beta-BHC	0.050 U.
3	319-86-8	Delta-BHC	0.050 U.
4	58-89-9	Gamma-BHC(Lindane)	0.050 U.
5	76-44-8	Heptachlor	0.050 U.
6	309-00-2	Aldrin	0.050 U.
7	1024-57-3	Heptachlor Epoxide	0.050 U.
8	959-98-8	Endosulfan I	0.050 U.
9	60-57-1	Dieldrin	0.100 U.
10	72-55-9	4,4'-DDE	0.100 U.
11	70-20-8	Endrin	0.100 U.
12	33213-65-9	Endosulfan II	0.100 U.
13	72-54-8	4,4-DDD	0.100 U.
14	1031-07-8	Endosulfan Sulfate	0.100 U.
15	50-29-3	4,4'-DDT	0.100 U.
16	53494-70-5	Endrin Ketone	0.100 U.
17	72-43-5	Methoxychlor	0.500 U.
18	57-74-9	Chlordane	0.500 U.
19	8001-35-2	Toxaphene	1.000 U.
20	12674-11-2	Aroclor-1016	NA
21	11104-28-2	Aroclor-1221	NA
22	11141-16-5	Aroclor-1232	NA
23	53469-21-9	Aroclor-1242	NA
24	12672-29-6	Aroclor-1248	NA
25	11097-69-1	Aroclor-1254	NA
26	11096-82-5	Aroclor-1260	NA

Total Pest = <1.0

40 CFR 414, OCPSF Pollutants

Pollutant	Sample Type	Test Results (Dec)	Test Results (Jan)	Test Results (Feb)	Federal Limits Daily Max / Mtly Avg	
Acenaphthene	C	______	______	______	47/19	*
Benzene	G	______	______	______	134/57	
Carbon Tetrachloride	G	______	______	______	380/142	
Chlorobenzene	G	______	______	______	380/142	
1,2,4-Trichlorobenzene	C	______	______	______	794/196	
Hexachlorobenzene	C	______	______	______	794/196	
1,2-Dichloroethane	G	______	______	______	574/180	
1,1,1-Trichloroethane	G	______	______	______	59/22	
Hexachloroethane	C	______	______	______	794/196	
1,1-Dichloroethane	G	______	______	______	59/22	
1,1,2-Trichloroethane	G	______	______	______	127/32	
Chloroethane	G	______	______	______	295/110	
Chloroform	G	______	______	______	325/111	
1,2-Dichlorobenzene	G	______	______	______	794/196	
1,3-Dichlorobenzene	G	______	______	______	380/142	
1,4-Dichlorobenzene	G	______	______	______	380/142	
1,1-Dichloroethylene	G	______	______	______	60/22	
1,2-Trans-dichloroethylene	G	______	______	______	66/25	
1,2-Dichloropropane	G	______	______	______	794/196	
1,3-Dichloropropylene	G	______	______	______	794/196	
2,4-Dimethylphenol	C	______	______	______	47/19	*
Ethylbenzene	G	______	______	______	380/142	
Fluoranthene	C	______	______	______	54/22	*
Methylene Chloride	G	______	______	______	170/36	
Methyl Chloride	G	______	______	______	295/110	
Hexachlorobutadiene	C	______	______	______	380/142	
Naphthalene	C	______	______	______	47/19	*
Nitrobenzene	C	______	______	______	6,402/2,237	
2-Nitrophenol	C	______	______	______	231/65	
4-Nitrophenol	C	______	______	______	576/162	
4,6-Dinitro-o-cresol	C	______	______	______	277/78	
Phenol	C	______	______	______	47/19	*
Bis(2-ethylhexyl) phthalate	C	______	______	______	258/95	*
Di-n-butyl phthalate	C	______	______	______	43/20	*
Diethyl phthalate	C	______	______	______	113/46	*
Dimethyl phthalate	C	______	______	______	47/19	*
Anthracene	C	______	______	______	47/19	*
Fluorene	C	______	______	______	47/19	*
Phenanthrene	C	______	______	______	47/19	*
Pyrene	C	______	______	______	48/20	*
Tetrachloroethylene	G	______	______	______	164/52	
Toluene	G	______	______	______	74/28	
Trichloroethylene	G	______	______	______	69/26	
Vinyl Chloride	G	______	______	______	172/97	
Total Cyanide	G	______	______	______	1,200/420	
Total Lead	C	______	______	______	690/320	
Total Zinc	C	______	______	______	2,610/1,050	
pH	G	______	______	______	5.0 S.U. Minimum	

G = Grab Sample C = Composite Sample * = Remanded

7a. Based on the above, the wastewater discharge:
______ is in compliance. ______ is not in compliance.

40 CFR 413 and 433

The term "TTO" shall mean total toxic organics, which is the summation of all quantifiable values greater than .01 milligrams per liter for the following toxic organics:

Acenaphthene
Acrolein
Acrylonitrile
Benzene
Benzidine
Carbon Tetrachloride (tetrachloromethane)
Chlorobenzene
1,2,4-trichlorobenzene
Hexachlorobenzene
1,2,-dichloroethane
1,1,1-trichloroethane
Hexachloroethane
1,1-dichloroethane
1,1,2-trichloroethane
1,1,2,2-tetrachloroethane
Chloroethane
Bis (2-chloroethyl) ether
2-chloroethyl vinyl ether (mixed)
2-chloronaphthalene
2,4,6-trichlorophenol
Parachlorometa cresol
Isophorone
Chloroform (trichloromethane)
2-chlorophenol
1,2-dichlorobenzene
1,3-dichlorobenzene
1,4-dichlorobenzene
3,3-dichlorobenzidine
1,1-dichloroethylene
1,2-trans-dichloroethylene
2,4-dichlorophenol
1,2-dichloropropane (1,3-dichloropropene)
2,4-dimethylphenol
2,4,-dinitrotoluene
2,6-dinitrotoluene
1,2-diphenylhydrazine
Ethylbenzene
Fluoranthene
4-Chlorophenyl phenyl ether
4-Bromophenyl phenyl ether
Bis (2-chloroisopropyl) ether
Bis (2-chloroethoxy) methane
Methylene Chloride (dichloromethane)
Methyl Chloride (chloromethane)
Methyl Bromide (bromomethane)
Bromoform (tribromomethane)
Dichlorobromomethane
Chlorodibromomethane

Napthalene
Nitrobenzene
2-nitrophenol
4-nitrophenol
2,4-dinitrophenol
4,6-dinitro-o-cresol
N-nitrosodimethylamine
N-nitrosodiphenylamine
N-nitrosodi-n-propylamine
Pentachlorophenol
Phenol
Bis (2-ethylhexyl) phthalate
Butyl benzyl phthalate
Di-n-butyl phthalate
Di-n-octyl phthalate
Diethyl phthalate
Dimethyl phthalate
1,2-benzanthracene
(benzo (a)anthracene)
Benzo(a)pyrene (3,4-benzopyrene)
3,4-Benzofluoranthene (benzo(b)fluoranthene)
11,12-Benzofluoranthene (Benzo(k)fluoranthene)
Chrysene
Acenapthylene
Anthracene
1,12-Benzoperylene (Benzo(ghi)perlene)
Fluorene
Phenanthrene
1,2,5,6-Dibenzanthracene (Dibenzo(a,h)anthracene)
Indeno(1,2,3-cd) pyrene (2,3-o-phenlene pyrene)
Pyrene
Tetrachloroethylene
Toluene
Trichloroethylene
Vinyl chloride (chloroethylene)

Aldrin
Dieldrin
Chlordane (technical mixture and metabolites)
4,4-DDT
4,4-DDE (p,p-DDX)
4,4-DDD (p,p-TDE)
Alpha-endosulfan
Beta-endosulfan
Endosulfan sulfate
Endrin
Endrin aldehyde
Heptachlor
Heptachlor epoxide
(BHC-hexachlorocyclohexane)
Alpha-BHC
Beta-BHC
Gamma-BHC
Delta-BHC

(PCB-polychlorinated biphenyls)
PCB-1242 (Arochlor 1242)
PCB-1254 (Arochlor 1254)
PCB-1221 (Arochlor 1221)
PCB-1232 (Arochlor 1232)
PCB-1248 (Arochlor 1248)
PCB-1260 (Arochlor 1260)
PCB 1016 (Arochlor 1216)
Toxaphene
2,3,7,8-Tetrachlorodibenzo-p-dioxin (TCDD)

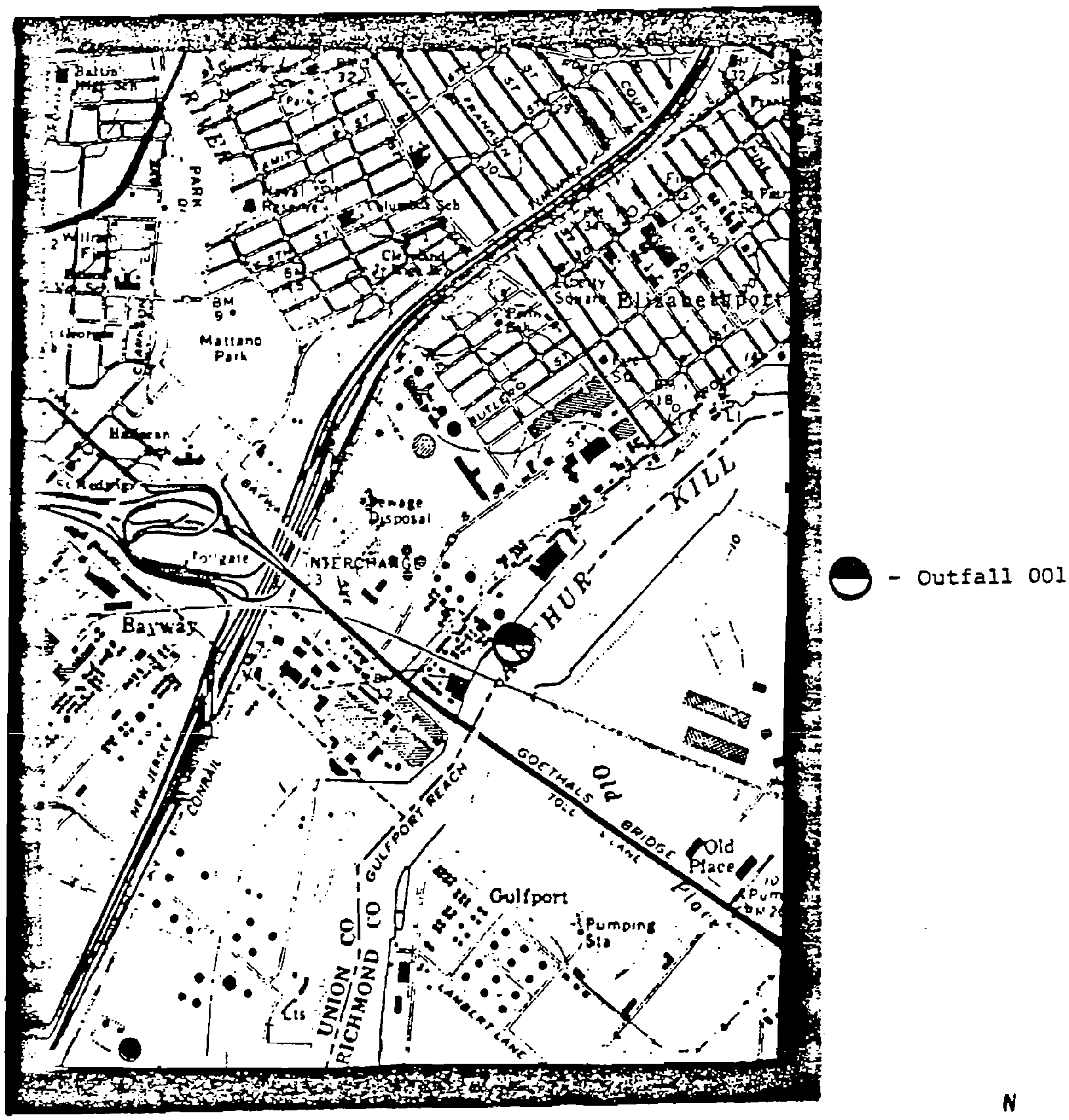


FIGURE 1

Location of Discharge
Joint Meeting of Essex and Union Counties
Wastewater Treatment Plant

NJ0024711

SCALE 1:24 000

1 0 1 MILE

1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

1 .5 0 1 KILOMETER

CONTOUR INTERVAL 10 FEET
NATIONAL GEODETIC VERTICAL DATUM OF 1929
DEPTH CURVES AND SOUNDINGS IN FEET—DATUM IS MEAN LOW WATER
THE RELATIONSHIP BETWEEN THE TWO DATUMS IS VARIABLE
SHORELINE SHOWN REPRESENTS THE APPROXIMATE LINE OF MEAN HIGH WATER

TABLE III-CSO-1

OWNER/OPERATOR	CSO #	CSO LOCATION	C O O R D	WATERBODY NAME	S-CL
Elizabeth	019	Bridge St, S Bank	40 39 38 74 12 44	Elizabeth River	SE3
Elizabeth	020	Bridge St, N Bank	40 39 39 74 12 43	Elizabeth River	SE3
Elizabeth	021	State Highway 25	40 39 32 74 12 33	Elizabeth River	SE3
Elizabeth	022	South St, E Bank	40 39 28 74 12 39	Elizabeth River	SE3
Elizabeth	023	South St, W Bank	40 39 28 74 12 40	Elizabeth River	SE3
Elizabeth	024	Norwood Terr.	40 39 25 74 12 40	Elizabeth River	SE3
Elizabeth	025	Montgomery St	40 39 22 74 12 40	Elizabeth River	SE3
Elizabeth	026	John Street	40 39 15 74 12 33	Elizabeth River	SE3
Elizabeth	027	Summer Street	40 38 59 74 12 37	Elizabeth River	SE3
Elizabeth	028	Summer Street	40 38 59 74 12 37	Elizabeth River	SE3
Elizabeth	029	Elizabeth Avenue	40 38 39 74 11 22	Arthur Kill	SE3
Elizabeth	030	E Jersey St	40 38 47 74 11 12	Arthur Kill	SE3
Elizabeth	031	Livingston Street	40 38 48 74 11 9	Arthur Kill	SE3
Elizabeth	032	Magnolia Avenue	40 38 51 74 10 53	Arthur Kill	SE3
Elizabeth	034	Trumbull St	40 39 7 74 10 15	Newark Bay	SE3
Elizabeth	035	Third Avenue	40 38 33 74 11 43	Elizabeth River	SE3
Elizabeth	001	Alina St. No. 1	40 40 49 74 11 30	Peripheral Ditch	FW2-NT
Elizabeth	002	Dowd Ave. No. 2	40 40 19 74 11 36	Great Ditch	FW2-NT
Elizabeth	003	Westfield Ave No 3	40 40 4 74 13 15	Elizabeth River	FW2-NT
Elizabeth	005	Westfield Ave. No. 5	40 40 4 74 13 11	Elizabeth River	FW2-NT
Elizabeth	006	Crane St. No. 6	40 40 1 74 13 9	Elizabeth River	FW2-NT
Elizabeth	007	W. Grant, E. Bank	40 39 58 74 13 9	Elizabeth River	FW2-NT
Elizabeth	008	W. Grand, W. Creek	40 39 58 74 13 8	Elizabeth River	FW2-NT
Elizabeth	009	Murray St., E. Bank	40 39 47 74 13 9	Elizabeth River	FW2-NT
Elizabeth	010	Murray St., W. Bank	40 39 47 74 13 10	Elizabeth River	FW2-NT
Elizabeth	011	Rahway Ave., W. Bank	40 39 41 74 13 6	Elizabeth River	FW2-NT
Elizabeth	012	Rahway Ave., E. Bank	40 39 41 74 13 4	Elizabeth River	FW2-NT
Elizabeth	013	S. of Rahway Ave.	40 39 39 74 13 4	Elizabeth River	FW2-NT
Elizabeth	014	Broad St., N. Bank	40 39 39 74 12 57	Elizabeth River	SE3
Elizabeth	015	Broad St., N. Bank	40 39 39 74 12 56	Elizabeth River	SE3
Elizabeth	016	Broad St., S. Bank	40 39 38 74 12 57	Elizabeth River	SE3
Elizabeth	017	Broad St., S. Bank	40 39 38 74 12 56	Elizabeth River	SE3
Elizabeth	036	Irvington Ave.Dod Ct	40 40 15 74 13 12	Elizabeth River	SE3
Elizabeth	037	Bayway	40 38 6 74 11 57	Arthur Kill	SE3
Elizabeth	038	Trenton Ave, E Bank	40 38 50 74 12 18	Elizabeth River	SE3
Elizabeth	039	Schiller St.	40 39 47 74 12 52	Great Ditch	FW2-NT
Elizabeth	040	Pulaski St.	40 38 47 74 12 32	Elizabeth River	SE3
Elizabeth	041	Morris Ave.	40 40 10 74 13 11	Elizabeth River	FW2-NT
Elizabeth	042	Bridge St.	40 39 32 74 12 43	Elizabeth River	SE3

s

STATEMENT OF BASIS/FACT SHEET
Addendum for Residuals Conditions
For NJPDES Permit to Discharge
Into the Waters of the State of New Jersey

I. NAMES AND ADDRESSES:

NJPDES Permit No: NJ0024741

FACILITY TYPE: Wastewater Treatment Plant

FACILITY LOCATION:

Joint Meeting of Essex and Union Counties
500 South First Street
Elizabeth, New Jersey 07202

NAME AND ADDRESS OF PERMITTEE:

Joint Meeting of Essex and Union Counties
500 South First Street
Elizabeth, New Jersey 07202

The following shall constitute an addendum to the fact sheet and statement of basis regarding issuance of the residuals conditions in the Revoke and Reissue Permit to the permittee above.

II. DESCRIPTION:

The facility currently generates approximately 73,000 dry lbs/day of sludge at a flow very close to the design flow of the sewage treatment plant. As defined in the Statewide Sludge Management Plan, sludge is "the solid residue and associated liquid resulting from physical, chemical or biological treatment of wastewater in a domestic treatment works." All sludge produced by the above named permittee is transported to Pennsylvania for landfill disposal until a long-term sludge management plan is implemented pursuant to the terms of a Judicial Consent Decree (JCD - Civil Action No. 89-3339 xx-HAA).

Major components of the sludge treatment and dewatering operation prior to its management consist of the following:

a) Coarse bar and fine screening.

b) Grit settlement and removal.

c) Primary settling.

d) Aeration of activated sludge.

e) Secondary clarification and chlorination.

f) Gravity and centrifuge thickening of primary and secondary sludges.

g) Anaerobic digestion.

h) Centrifuge dewatering.

The sludge dewatering facility also consists of storage capabilities, lime stabilization processes, filtrate return systems, compressed air systems and controls and instrumentation.

III. BASIS FOR PERMIT CONDITIONS

All Residuals Management Conditions have been incorporated into the draft Revoke and Reissue Permit in accordance with the requirements of the NJPDES Regulations, N.J.A.C. 7:14A-1 et seq., promulgated pursuant to the authority of the following applicable acts:

(a) New Jersey "Water Pollution Control Act" and amendments N.J.S.A. 58:10A-1 et seq.

(b) New Jersey "Solid Waste Management Act" and amendments N.J.S.A. 13:1E-1 et seq.

In addition, pursuant to the Water Quality Planning Act (N.J.S.A. 58:11A-1 et seq.), the Statewide Sludge Management Plan and N.J.A.C. 7:14A-3.13 (a)15, the JMEUC submitted a plan for management of the residuals projected to be produced at the treatment plant. The Department found said plan to meet the requirements of the Statewide Sludge Management Plan on July 12, 1989. Accordingly, the conditions of the Generator Sludge Management Plan have been incorporated into the draft Revoke and Reissue Permit. Any subsequent modification to the JCD may necessitate the appropriate modification(s) to the sludge management plan.

IV. PROCEDURES OF REACHING A FINAL DECISION ON THE PERMIT

The appearance of the public notice in the newspapers marks the commencement of the mandatory 30 day comment period required by Section 8.1 of the New Jersey Pollutant Discharge Elimination System Regulations, N.J.A.C. 7:14A-1 et seq. During this time frame, both the permittee and concerned citizens may offer comments concerning the terms and conditions of this draft permit or may request that a non-adversarial public hearing be conducted whenever the NJDEPE determines that there is significant public interest in the permit decision. All comments must be submitted within the appropriate time frame and in writing to:

Administrator
New Jersey Department of Environmental Protection and Energy
Wastewater Facilities Regulation Program
CN-029
Trenton, New Jersey 08625

V. DEPE CONTACT

Additional information concerning the residuals conditions of this permit may be obtained between the hours of 8:30 A.M. and 4:00 P.M., Monday through Friday from: Marc Kerachsky at (609) 633-3823.

3

THE INTERSTATE SANITATION COMMISSION AND THE CITY OF ELIZABETH

A CASE STUDY IN INTERGOVERNMENTAL ENFORCEMENT

by

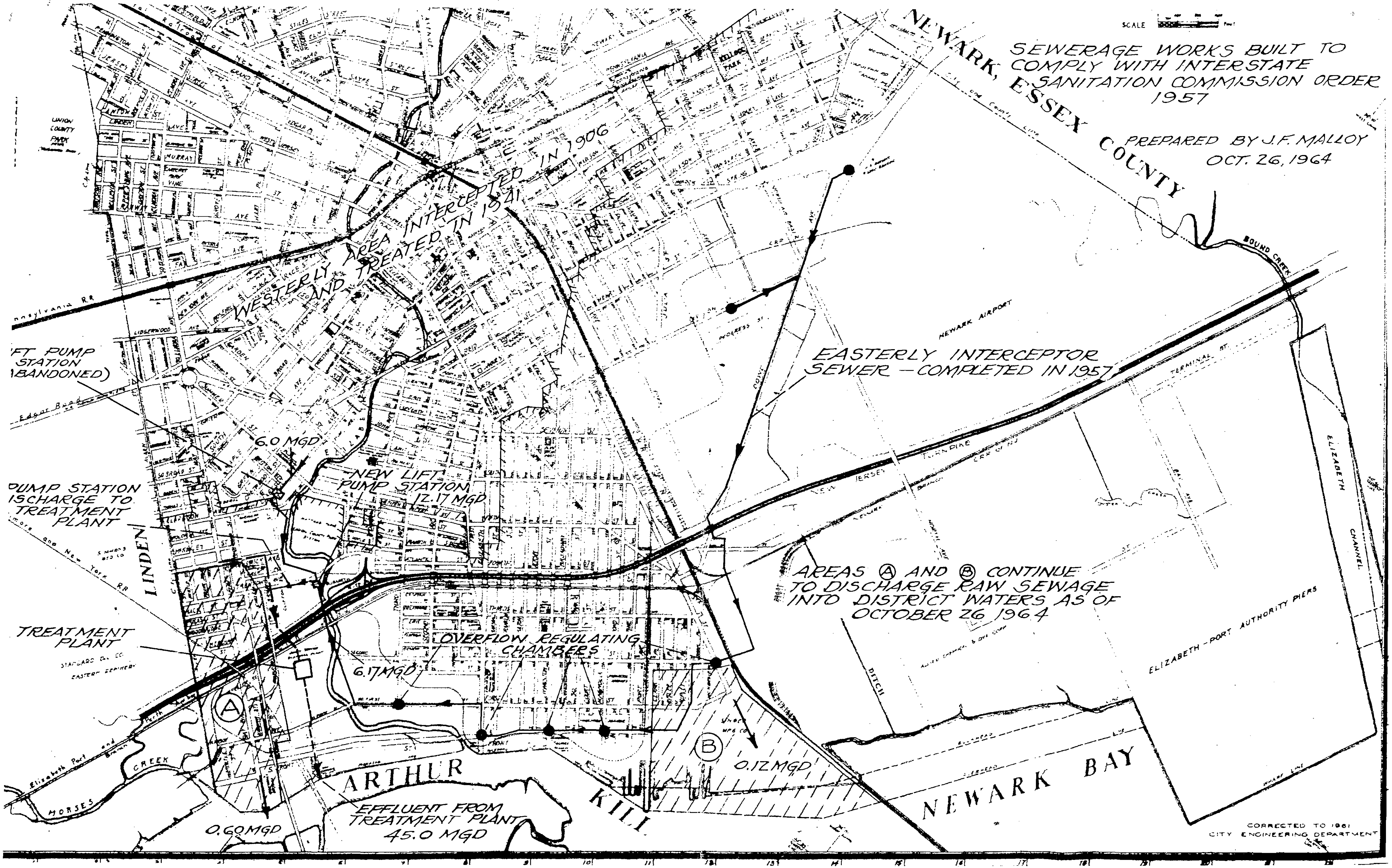
John F. Malloy, Jr.

A thesis presented to the faculty of the
Graduate School of Public Administration,
New York University in partial fulfillment
of the requirements for the degree of
Master of Public Administration.

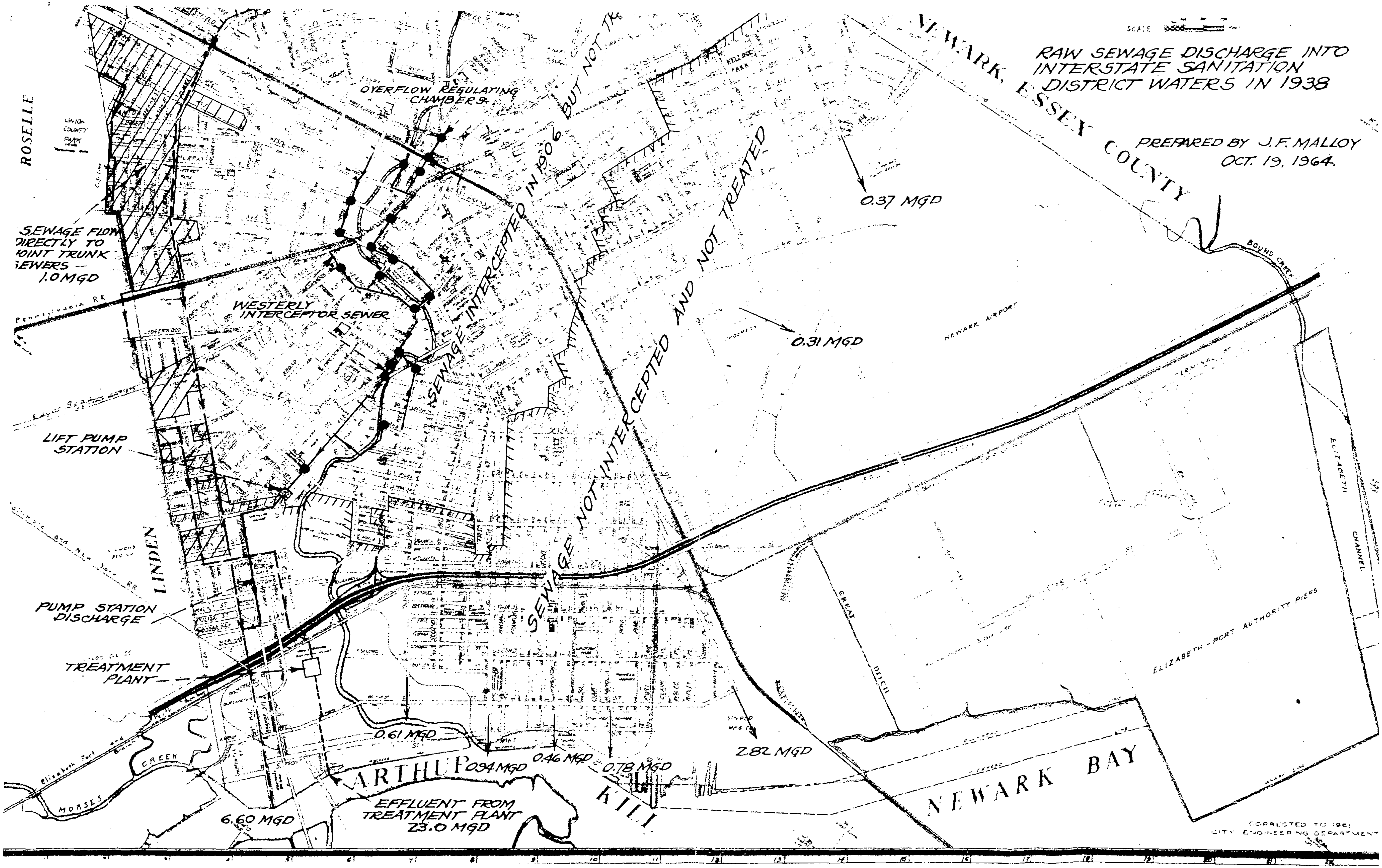
Graduate School of Public Administration

New York University
4 Washington Square
New York 3, New York

June, 1965



SEWERAGE WORKS BUILT TO COMPLY WITH INTERSTATE SANITATION COMMISSION ORDER 1957
PREPARED BY J.F. MALLOY OCT. 26, 1964
NEWARK, ESSEX COUNTY
WESTERLY AREA INTERCEPTED IN 1906 AND TREATED IN 1941
EASTERLY INTERCEPTOR SEWER – COMPLETED IN 1957
NEWARK AIRPORT
FT PUMP STATION BANDONED)
6.0 MGD
NEW LIFT PUMP STATION 12.17 MGD
PUMP STATION ISCHARGE TO TREATMENT PLANT
AREAS Ⓐ AND Ⓑ CONTINUE TO DISCHARGE RAW SEWAGE INTO DISTRICT WATERS AS OF OCTOBER 26 1964
TREATMENT PLANT
OVERFLOW REGULATING CHAMBERS
6.17 MGD
LINDEN
A
B
0.12 MGD
ARTHUR KILL
NEWARK BAY
EFFLUENT FROM TREATMENT PLANT 45.0 MGD
0.60 MGD
ELIZABETH CHANNEL
ELIZABETH-PORT AUTHORITY PIERS
BOUND CREEK
MORSES CREEK
UNION COUNTY PARK
Pennsylvania RR
NEW JERSEY TURNPIKE
SCALE
CORRECTED TO 1961 CITY ENGINEERING DEPARTMENT



RAW SEWAGE DISCHARGE INTO
INTERSTATE SANITATION
DISTRICT WATERS IN 1938
PREPARED BY J.F. MALLOY
OCT. 19, 1964.
NEWARK, ESSEX COUNTY
ROSELLE
LINDEN
OVERFLOW REGULATING
CHAMBERS
SEWAGE FLOW
DIRECTLY TO
JOINT TRUNK
SEWERS —
1.0 MGD
WESTERLY
INTERCEPTOR SEWER
SEWAGE INTERCEPTED IN 1906 BUT NOT TR
SEWAGE NOT INTERCEPTED AND NOT TREATED
LIFT PUMP
STATION
PUMP STATION
DISCHARGE
TREATMENT
PLANT
0.37 MGD
0.31 MGD
NEWARK AIRPORT
BOUND CREEK
ELIZABETH CHANNEL
GREAT DITCH
ELIZABETH-PORT AUTHORITY PIERS
NEWARK BAY
ARTHUR KILL
MORSES CREEK
0.61 MGD
0.94 MGD
0.46 MGD
0.78 MGD
2.82 MGD
6.60 MGD
EFFLUENT FROM
TREATMENT PLANT
23.0 MGD
Pennsylvania RR
CORRECTED TO 1961
CITY ENGINEERING DEPARTMENT

Fig. 7.

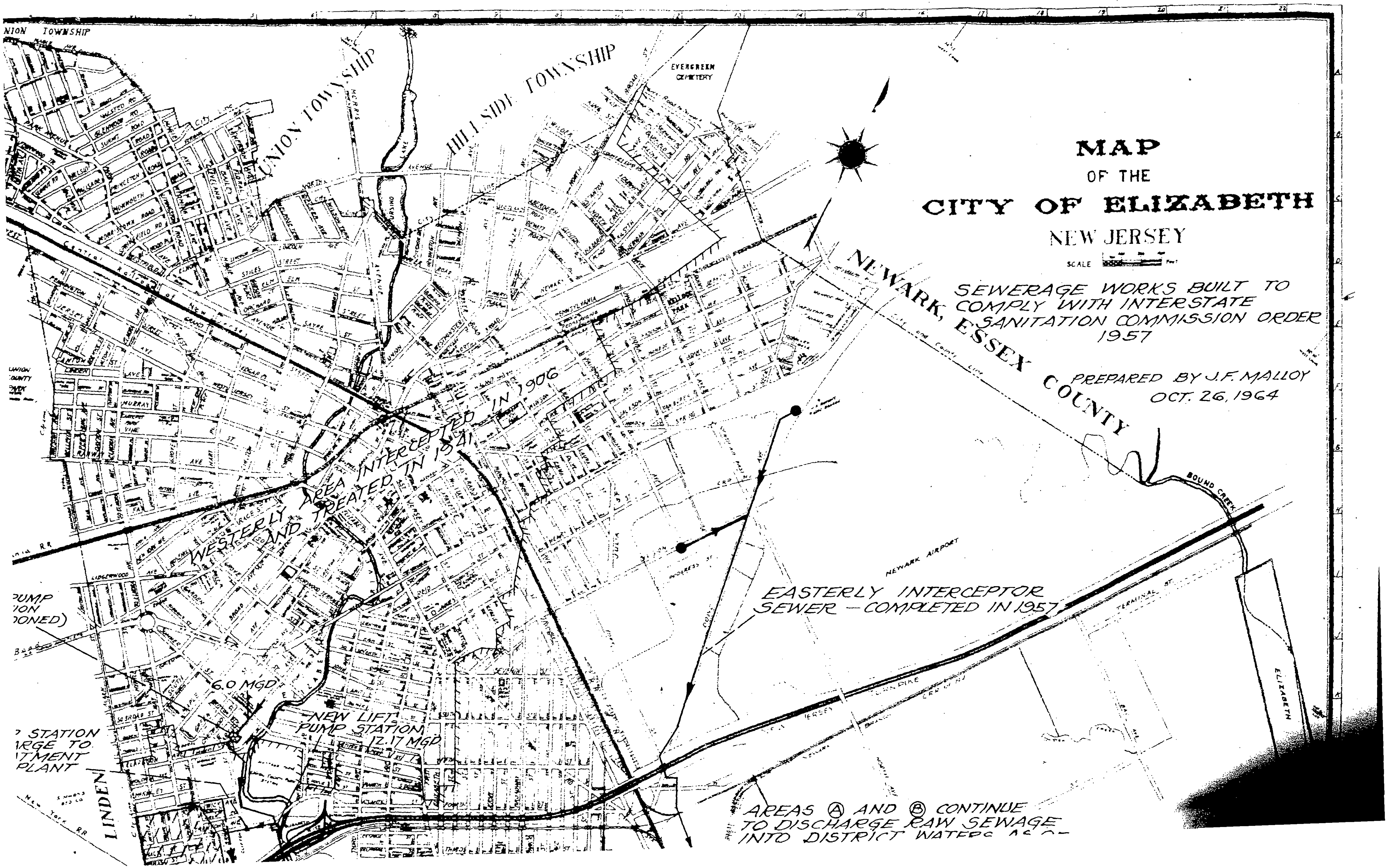
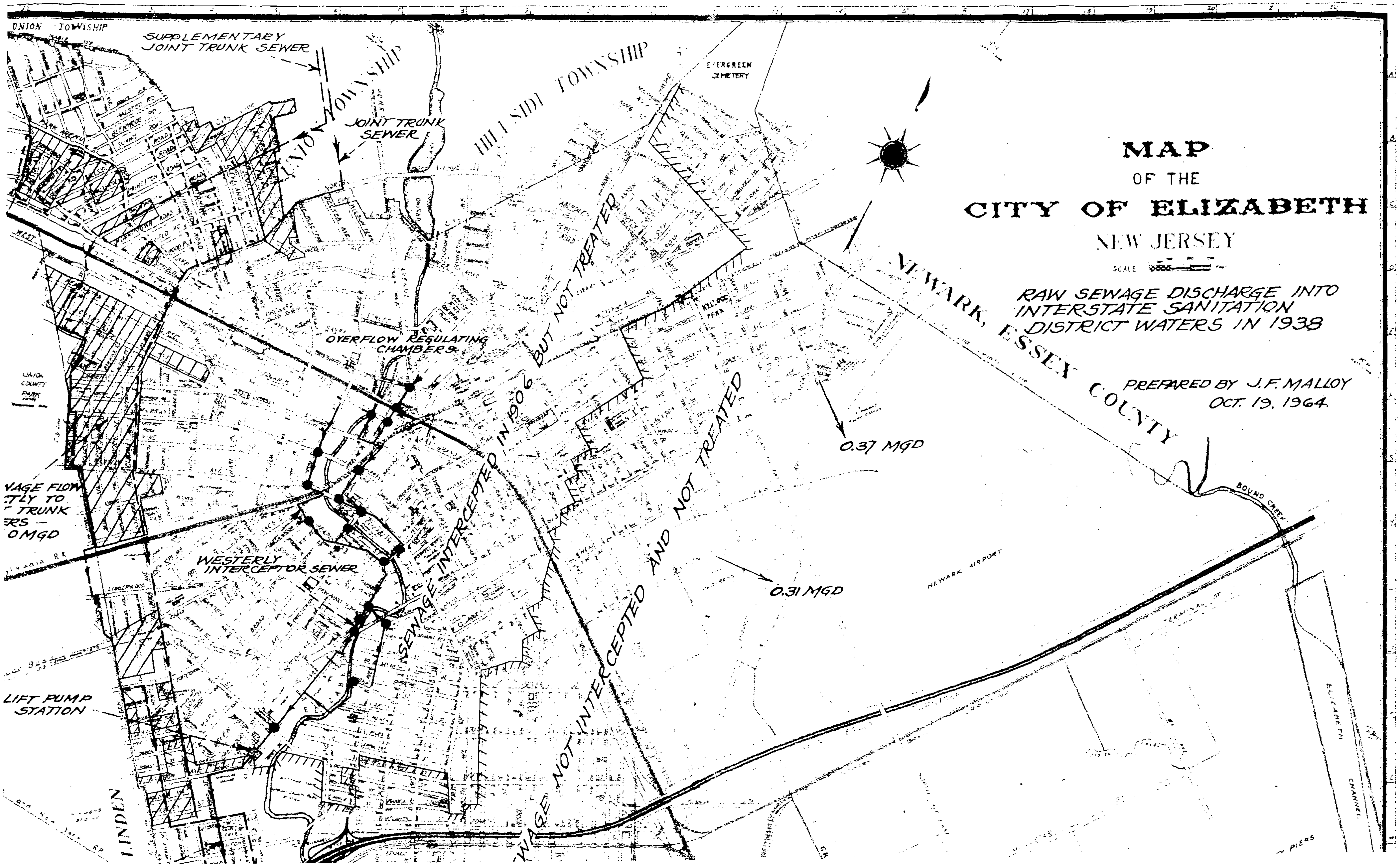

MAP
OF THE
CITY OF ELIZABETH
NEW JERSEY
SCALE
SEWERAGE WORKS BUILT TO COMPLY WITH INTERSTATE SANITATION COMMISSION ORDER 1957
PREPARED BY J.F. MALLOY OCT. 26, 1964
UNION TOWNSHIP
HILLSIDE TOWNSHIP
EVERGREEN CEMETERY
NEWARK, ESSEX COUNTY
WESTERLY AREA INTERCEPTED IN 1906 AND TREATED IN 1941
EASTERLY INTERCEPTOR SEWER - COMPLETED IN 1957
NEWARK AIRPORT
BOUND CREEK
6.0 MGD
NEW LIFT PUMP STATION 12.17 MGD
AREAS Ⓐ AND Ⓑ CONTINUE TO DISCHARGE RAW SEWAGE INTO DISTRICT WATERS AS OF
LINDEN
ELIZABETH
TERMINAL ST.

Fig. 2.



MAP
OF THE
CITY OF ELIZABETH
NEW JERSEY
SCALE
RAW SEWAGE DISCHARGE INTO INTERSTATE SANITATION DISTRICT WATERS IN 1938
PREPARED BY J.F. MALLOY
OCT. 19, 1964.
UNION TOWNSHIP
SUPPLEMENTARY JOINT TRUNK SEWER
UNION TOWNSHIP
JOINT TRUNK SEWER
HILLSIDE TOWNSHIP
EVERGREEN CEMETERY
NEWARK, ESSEX COUNTY
OVERFLOW REGULATING CHAMBERS
SEWAGE INTERCEPTED IN 1906 BUT NOT TREATED
WAGE NOT INTERCEPTED AND NOT TREATED
0.37 MGD
0.31 MGD
WESTERLY INTERCEPTOR SEWER
LIFT PUMP STATION
UNION COUNTY PARK
LINDEN
BOUND CREEK
NEWARK AIRPORT
ELIZABETH CHANNEL
PIERS

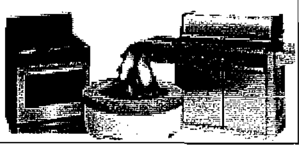
4

Elizabethtown Gas
An AGL Resources Company

1-800-492-4009
Natural Gas Leaks, Odors or Emergencies

Our Service Territory
Find out where we serve >

Natural Gas Appliances
Find what you're looking for here...it's easy!



Find a Natural Gas Advantage Dealer
Locate a Heating and Cooling dealer in your area
Search Now >

About Us

Our Role

Elizabethtown Gas, a subsidiary of AGL Resources, serves more than 260,000 residential, business and industrial natural gas customers in New Jersey. We serve parts of Union, Middlesex, Sussex, Warren, Hunterdon, Morris and Mercer counties. Our parent company, AGL Resources (NYSE:ATG), is positioned to become one of the nation's preeminent distributors of natural gas.

Our History

1855 Elizabethtown Gas was founded to fuel the 300 gaslights lining the streets of the city now known as Elizabeth, N.J. For the first century of our existence, Elizabethtown Gas used coal to manufacture the gas we delivered.
1951 Our company converted to natural gas, which was delivered to New Jersey through a network of interstate pipelines.
1969 NUI was founded, and Elizabethtown Gas became part of the corporation.
2004 Elizabethtown Gas became a subsidiary of AGL Resources Inc. (NYSE:ATG), an Atlanta-based energy holding company.
Today As part of the AGL Resources family, we constantly strive to provide efficient, economical and reliable service to our customers.

BAC000001

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Nui Corp · 8-K · For 3/15/95 · EX-99

Filed On 3/15/95 · SEC File 1-08353 · Accession Number 70668-95-18

As Of	Filer	Filing	On/For/As	Docs:Pgs
3/15/95	Nui Corp	**8-K**{5,7}	3/15/95	2:6

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EX-99 · Miscellaneous Exhibit

EXHIBIT 99

For Immediate Release

NUI CORPORATION HOLDS ANNUAL MEETING

RESTRUCTURING PLAN ANNOUNCED

Union, N.J. -- March 14, 1995 -- NUI Corporation (National Utility Investors; NYSE: NUI) hosted its 141st Annual Meeting of Shareholders today at the company's Elizabethtown Gas offices in Union, N.J. During the planned remarks, John Kean, Chairman and Chief Executive Officer of NUI Corporation, reviewed the company's results during the past year and highlighted the entrance of *"change"* and *"competition"* in the gas distribution industry, marked by the end of the monopolistic era.

Kean, Jr. Named CEO

John Kean, Jr., 37, who serves as President and Chief Operating Officer of the multi-state utility was earlier in the day named Chief Executive Officer, effective April 1, succeeding his father. Mr. Kean, Jr. was also elected to the NUI Board of Directors. (See related announcement). During the Annual Meeting, Kean, Jr. outlined the company's plan to restructure operations and updated shareholders on cost-cutting and other streamlining efforts, designed to further strengthen NUI's operating position in the years to come.

Consolidation of Pennsylvania & Southern and City Gas divisions

Mr. Kean, Jr. announced the merger of the company's Pennsylvania & Southern Gas Company and City Gas Company of Florida divisions to create a Southern Division and eliminate certain redundancies within the Corporation. Lyle C. Motley, Jr., 53, currently President of Pennsylvania & Southern Gas Company, was named President of the Southern Division, also effective April 1.

The Southern Division will be based in Hialeah, Florida and will serve the 114,000 customers of City Gas Company of Florida, North Carolina Gas Service, Elkton Gas Service, Valley Cities Gas Service, and Waverly Gas Service. The service area will encompass over 1,500 square miles.

Following the relocation of key personnel and consolidation of divisional functions, the Sayre, Pennsylvania office, formerly the corporate offices of Pennsylvania & Southern Gas Company, will be closed.

Change and Competition

As part of today's meeting, the company featured a series of displays documenting the changes the gas distribution industry has undergone over the years. Included in the displays were discussions of the shift in the regulatory framework, the advent of transportation or *"unbundled"* service in New Jersey, and the profound changes affecting the gas supply component of the industry, as well as features of new NUI customers.

In his comments, Mr. Kean, Jr. noted, "We are excited and ready to compete in the new gas marketplace. Operating in one of the first states to unbundle the commercial market, NUI is provided a unique opportunity to be one of the first utilities in the United States to gain experiences in this new level of deregulation."

Elizabethtown Gas Company Restructures

Kean, Jr. also announced the restructuring of the New Jersey division's operations to facilitate greater operational and customer service efficiency. Effective April 1, David Vincent, 51, formerly Chief Financial Officer of NUI Corporation, will join Elizabethtown Gas as Senior Vice President, to oversee common service functions for NUI, including Management Information Systems, Marketing support, Risk Management and Purchasing. Mary Patricia Keefe and Richard O'Neill, currently Group Vice Presidents of Elizabethtown Gas, were also named Senior Vice Presidents of Elizabethtown Gas.

Early Retirement Program Results Announced

Kean, Jr. also reviewed the results of the company's early retirement programs, instituted in the New Jersey and Pennsylvania & Southern divisions to reduce workforce. The company has achieved its target of a 10 percent reduction in workforce, including 95 participants in the early retirement programs. Kean, Jr. announced the company will take a pre-tax charge of $4.1 million in the second quarter to reflect costs associated with the program. Going forward, this reduction in workforce is expected to generate approximately $3.4 million (pre-tax) in annual savings.

Complementing the company's workforce reduction efforts, Kean highlighted savings achieved through administrative changes in the company's health plans and results from the company's renegotiation of labor contracts in November, which resulted in greater operating flexibility.

Shareholders Approve All Proposals Set Forth by Management

During the Annual Meeting, shareholders approved all proposals set forth by management.

NUI Corporation (National Utility Investors; NYSE: NUI), based in Bedminster, N.J., is a multi-state gas utility serving over 347,000 customers in six states. The company's operating divisions include Elizabethtown Gas Company, City Gas Company of Florida, North Carolina Gas Service, Valley Cities Gas Service (PA), Waverly Gas Service (NY) and Elkton Gas Service (MD).

###

Contact: Alexandra Pruner
908/719-4222

Dates Referenced Herein ***and*** **Documents Incorporated By Reference**

This 8-K Filing	*Date*	*Referenced-On Page First*	*Referenced-On Page Last*	*Other Filings*
	3/14/95	1		DEF 14A
Filed On / Filed As Of / For The Period Ended	3/15/95			

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Alternative Formats: Rich Text / Word (.rtf), Text (.txt), EDGAR (.sgml), XML (.xml), et al.

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Nui Corp · 8-K · For 3/2/01

Filed On 3/2/01 5:07pm ET · SEC File 1-08353 · Accession Number 898080-1-98

As Of	Filer	Filing	As/For/On	Docs:Pgs	Issuer	Agent
3/02/01	Nui Corp	**8-K**{5,7}	3/02/01	3:10		Leboeuf Lamb Gre..Macrae

Current Report · Form 8-K
Filing Table of Contents

Document/Exhibit		Description	Pages	Size
1:	**8-K**	**Current Report**	**4**	**16K**
2:	EX-2	Exchange Agreement	4±	18K
3:	EX-4	Rights Plan Amendment 1	2±	12K

8-K · Current Report
Document Table of Contents

Page *(sequential)* *(alphabetic)* Top

BAC000003

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 8-K

Current Report

Pursuant to Section 13 or 15(d) of the

Securities Exchange Act of 1934

Date of Report (Date of Earliest Event Reported): March 2, 2001

[Enlarge/Download Table]

Commission File Number	Exact Name of Registrant as Specified in its Charter	State of Incorporation	IRS Employer Identification Number	Registrant's Telephone Number
N/A	NUI Corporation	New Jersey	22-3708029	(908) 781-0500
1-8353	NUI Utilities, Inc.	New Jersey	22-1869941	(908) 781-0500

550 Route 202-106, P.O. Box 760, Bedminster, New Jersey, 07291-0760

(Address of both registrants' principal executive offices, including zip code)

NUI Corporation was previously known as *"NUI Holding Company"*

NUI Utilities, Inc. was previously known as *"NUI Corporation"*

(Former name or former address, if changed since last report)

Item 5. Other Events

Effective March 1, 2001, NUI Corporation (currently *"NUI Utilities, Inc."*) was reorganized into a holding company structure pursuant to an Agreement and Plan of Exchange (the *"Exchange Agreement"*) between NUI Corporation, subsequently renamed NUI Utilities, Inc. (*"NUI"*), and NUI Holding Company, subsequently renamed NUI Corporation (*"Holding Company"*). The Exchange Agreement was approved by NUI's shareholders at the Annual Meeting of Shareholders held on March 27, 2000. Under the Exchange Agreement, each outstanding share of NUI common stock was exchanged automatically by operation of law on a share-for-share basis for Holding Company common stock. Each share of Holding Company common stock previously issued to NUI was then canceled. This transaction resulted in NUI becoming a wholly owned subsidiary of Holding Company.

The Holding Company common shares issued to the NUI shareholders pursuant to the Exchange Agreement were registered under the Securities Act of 1933 pursuant to Holding Company's Registration Statement on Form S-4 filed with the Securities and Exchange Commission (the *"SEC"*) (File No. 333-30092) and declared effective on February 11, 2000. See the Proxy Statement and Prospectus of NUI and Holding Company included in the Registration Statement for additional information.

Pursuant to Rule 12g-(3)(a) under the Securities Exchange Act of 1934, as amended, (the *"Exchange Act"*), Holding Company shares are deemed to be registered under Section 12(b) of the Exchange Act. The shares have been approved for listing by the New York Stock Exchange.

As of March 2, 2001, shares of NUI common stock are no longer listed on the New York Stock Exchange. In addition, NUI is filing a Form 15 with the SEC to terminate registration under the Exchange Act of shares of its common stock.

In connection with the reorganization, pursuant to the Exchange Agreement, NUI and Mellon Securities Trust Company (*"Mellon"*) entered into a First Amendment to the Rights Agreement between NUI and Mellon, dated as of February 26, 2001 (*"Amendment"*). The Amendment precludes the reorganization from triggering a distribution of rights under the plan, and provides that the rights shall expire upon the consummation of the reorganization and is file as an exhibit to this report.

Item 7. Financial Statements and Exhibits

(c) Exhibits

2 Agreement and Plan of Exchange between NUI Corporation (subsequently renamed NUI Utilities, Inc.) and NUI Holding Company (subsequently renamed NUI Corporation) dated as of March 1, 2001.

4 First Amendment to the Rights Agreement, dated as of November 28, 1995 between NUI Corporation and Mellon Securities Trust Company.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned hereunto duly authorized.

NUI CORPORATION

By: /s/ ***James R. Van Horn***

Name: James R. Van Horn
Title: Chief Administrative Officer,
General Counsel and Secretary

NUI UTILITIES, INC.

By: /s/ ***James R. Van Horn***

Name: James R. Van Horn
Title: Chief Administrative Officer,
General Counsel and Secretary

Date: March 2, 2001

INDEX TO EXHIBITS

Number	Description
2	Agreement and Plan of Exchange between NUI Corporation (subsequently renamed NUI Utilities, Inc.) and NUI Holding Company (subsequently renamed NUI Corporation) dated as of March 1, 2001.
4	First Amendment to the Rights Agreement, dated as of November 28, 1995 between NUI Corporation and Mellon Securities Trust Company.

Dates Referenced Herein ***and*** **Documents Incorporated By Reference**

This 8-K Filing	***Date***	***Referenced-On Page First***	***Last***	***Other Filings***
	11/28/95	2	4	8-K
	2/11/00	2		
	3/27/00	2		
	2/26/01	2		
	3/1/01	2	4	
Filed On / Filed As Of / For The Period Ended	3/2/01	1	3	

Top List All Filings

Alternative Formats: Rich Text / Word (.rtf), Text (.txt), EDGAR (.sgml), XML (.xml), et al.

Nui Corp · 8-K · For 3/2/01 · EX-2

Filed On 3/2/01 5:07pm ET · SEC File 1-08353 · Accession Number 898080-1-98

As Of	Filer	Filing	As/For/On	Docs:Pgs	Issuer	Agent
3/02/01	Nui Corp	**8-K**{5,7}	3/02/01	3:10		Leboeuf Lamb Gre..Macrae

Current Report · Form 8-K
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EX-2 · Exchange Agreement

AGREEMENT AND PLAN OF EXCHANGE

This AGREEMENT AND PLAN OF EXCHANGE (this *"Agreement"*), dated as of March 1, 2001, is between NUI CORPORATION, a New Jersey corporation (the *"Company"*), the company whose shares will be acquired pursuant to the Exchange described herein, and NUI Holding Company, a New Jersey corporation (*"NUI Holding Co."*), the acquiring company. The Company and NUI Holding Co. are hereinafter referred to, collectively, as the *"Companies."*

WITNESSETH:

WHEREAS, the authorized capital stock of the Company consists of (a) 30,000,000 shares of Common Stock, without par value (*"Company Common Stock"*), of which 13,122,429 shares are issued and outstanding, and (b) 5,000,000 shares of Preferred Stock, par value, of which no shares are issued and outstanding; the number of shares of Company Common Stock being subject to increase to the extent that shares reserved for issuance are issued prior to the Effective Time, as hereinafter defined;

WHEREAS, NUI Holding Co. is a wholly owned subsidiary of the Company with authorized capital stock consisting of (a) 30 million shares of Common Stock, without par value (*"NUI Holding Co. Common Stock"*), of which 100 shares are issued and outstanding and owned of record by the Company and (b) 5 million shares of Preferred Stock, without par value (*"NUI Holding Co. Preferred Stock"*), of which no shares are issued and outstanding;

WHEREAS, the Boards of Directors of the respective Companies deem it desirable and in the best interests of the Companies and the shareholders of the Company that each share of Company Common Stock be exchanged for a share of NUI Holding Co. Common Stock with the result that NUI Holding Co. becomes the owner of all outstanding Company Common Stock and that each holder of Company Common Stock becomes the owner of an equal number of shares of NUI Holding Co. Common Stock, all on the terms and conditions hereinafter set forth; and

WHEREAS, the Boards of Directors of the Companies have each approved and adopted this Agreement and the Board of Directors of the Company has recommended that its shareholders approve this Agreement pursuant to the New Jersey Business Corporation Act (the *"Act"*) and the shareholders have approved this Agreement;

WHEREAS, the parties hereto agree that at the Effective Time (as hereinafter defined) each share of Company Common Stock issued and outstanding immediately prior to the Effective Time will be exchanged for one share of NUI Holding Co. Common Stock (the *"Exchange"*);

WHEREAS, for U.S. federal income tax purposes, it is intended that the Exchange will constitute a transaction described in section 351 of the Internal Revenue Code of 1986, as amended (the "Code);

NOW, THEREFORE, in consideration of the premises, and of the agreements, covenants and conditions hereafter contained in this Agreement, the parties agree as follows:

ARTICLE I

This Agreement was approved by the shareholders of the Company entitled to vote with respect thereto for approval as provided by the Act.

ARTICLE II

Subject to the satisfaction of the terms and conditions set forth in this Agreement and to the provisions of Article VI, NUI Holding Co. agrees to file with the Secretary of State of the State of New Jersey (the *"Secretary of State"*) a Certificate of Share Exchange (the *"Certificate"*) with respect to the Exchange, and the Exchange shall take effect upon the effective date as specified in the Certificate (the *"Effective Time"*).

ARTICLE III

A. At the Effective Time:

(1) each share of Company Common Stock issued and outstanding immediately prior to the Effective Time shall be automatically exchanged for one share of NUI Holding Co. Common Stock, which shares shall thereupon be fully paid and non-assessable;

(2) NUI Holding Co. shall acquire and become the owner and holder of each issued and outstanding share of Company Common Stock so exchanged;

(3) each share of NUI Holding Co. Common Stock issued and outstanding immediately prior to the Effective Time shall be canceled and shall thereupon constitute an authorized and unissued share of NUI Holding Co. Common Stock;

(4) each share of Company Common Stock held under NUI's Dividend Reinvestment and Common Stock Purchase Plan, 1988 Stock Plan, 1996 Stock Option and Stock Award Plan, 1996 Employee Stock Purchase Plan and 1996 Director Stock Purchase Plan (including fractional and uncertificated shares) immediately prior to the Effective Time shall be automatically exchanged for a like number of

shares (including fractional and uncertificated shares) of NUI Holding Co. Common Stock, which shares shall be held under NUI's Dividend Reinvestment and Common Stock Purchase Plan, 1988 Stock Plan, 1996 Stock Option and Stock Award Plan, 1996 Employee Stock Purchase Plan and 1996 Director Stock Purchase Plan, as the case may be; and

(5) the former owners of Company Common Stock shall be entitled only to receive shares of NUI Holding Co. Common Stock as provided herein.

B. As of the Effective Time, NUI Holding Co. shall succeed to the Dividend Reinvestment and Common Stock Purchase Plan as in effect immediately prior to the Effective Time, and the Dividend Reinvestment and Stock Purchase Plan shall be appropriately amended to provide for the issuance and delivery of NUI Holding Co. Common Stock on and after the Effective Time.

C. As of the Effective Time, the 1988 Stock Plan, 1996 Stock Option and Stock Award Plan, 1996 Employee Stock Purchase Plan and 1996 Director Stock Purchase Plan shall be appropriately amended to provide for the issuance and delivery of NUI Holding Co. Common Stock on and after the Effective Time.

ARTICLE IV

The filing of the Certificate with the Secretary of State and the consummation of the Exchange are subject to the satisfaction of the following conditions precedent:

(1) the approval for listing, upon official notice of issuance, by the New York Stock Exchange, of NUI Holding Co. Common Stock to be issued and reserved for issuance pursuant to the Exchange;

(2) the receipt of such orders, authorizations, approvals or waivers from the New Jersey Board of Public Utilities, the Florida Public Service Commission, the North Carolina Utilities Commission, the Maryland Public Service Commission, the New York Public Service Commission, the Pennsylvania Public Utility Commission and all other regulatory bodies, boards or agencies as are required in connection with the Exchange, which orders, authorizations, approvals or waivers remain in full force and effect and do not include, in the sole judgment of the Board of Directors of the Company, unacceptable conditions; and

(3) the receipt by the Company of a tax opinion of LeBoeuf, Lamb, Greene & MacRae L.L.P. (*"LeBoeuf"*) satisfactory to the Board of Directors of the Company to the effect that the Exchange will be treated as a transaction described in Section 351 of the Code. In rendering such opinion, LeBoeuf shall be entitled to rely upon customary assumptions and representations of the Company and NUI Holding Company that are in form and substance reasonably satisfactory to LeBoeuf.

ARTICLE V

Following the Effective Time, each outstanding certificate which, immediately prior to the Effective Time, represented Company Common Stock shall be deemed and treated for all corporate purposes to represent the ownership of the same number of shares of NUI Holding Co. Common Stock. The holders of Company Common Stock at the Effective Time shall have no right to have their shares of Company Common Stock transferred on the stock transfer books of the Company, and such stock transfer books shall be deemed to be closed for this purpose at the Effective Time.

ARTICLE VI

This Agreement may be amended, modified or supplemented, or compliance with any provision or condition hereof may be waived, at any time, by the mutual consent of the Boards of Directors of the Company and of NUI Holding Co.; provided, however, that no such amendment, modification, supplement or waiver shall be made or effected, if such amendment, modification, supplement or waiver would, in the judgment of the Board of Directors of the Company, materially and adversely affect the shareholders of the Company.

Notwithstanding shareholder approval of this Agreement, this Agreement may be terminated and the Exchange and related transactions abandoned at any time prior to the time the Certificate is filed with the Secretary of State, if the Board of Directors of the Company determines, in its sole discretion, that consummation of the Exchange would be inadvisable or not in the best interests of the Company or its shareholders.

IN WITNESS WHEREOF, each of the Company and NUI Holding Co., pursuant to authorization and approval given by its Board of Directors, has caused this Agreement to be executed as of the date first above written.

NUI CORPORATION

By: /s/ ***John Kean, Jr.***

Name: John Kean, Jr.
Title: President

NUI HOLDING COMPANY

By: /s/ ***John Kean, Jr.***

Name: John Kean, Jr.
Title: President

Dates Referenced Herein ***and*** **Documents Incorporated By Reference**

This 8-K Filing	*Date*	*Referenced-On Page First*	*Last*	*Other Filings*
	3/1/01	1		
Filed On / Filed As Of / For The Period Ended	3/2/01			

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Decide with Confidence

Business Information Report

To save report(s) to your PC, click here for instructions. Print this Report

ATTN: **jbenthin@intell-group.com**

Report Printed: NOV 30 2007
In Date

BUSINESS SUMMARY

NUI CORPORATION
(SUBSIDIARY OF AGL RESOURCES INC, ATLANTA, GA)
550 Route 202-206
Bedminster, NJ 07921

Rating Change

Our information indicates this business is no longer active at this location. If you have reason to believe this business is currently operating, please call our Customer Service Center at the phone number listed below to request an investigation.

This is a **headquarters (subsidiary)** location. Branch(es) or division(s) exist.

D-U-N-S Number: 06-015-2233

D&B Rating: **NQ** Formerly 1R3

Mailing address:	PO Box 760 Bedminster, NJ 07921
Web site:	www.aglresources.com
Telephone:	NONE
Chief executive:	PAULA G ROSPUT, CHB-PRES-CEO+
Employs:	960
History:	CLEAR
SIC:	4932
Line of business:	Natural gas distribution & other combined servies

SPECIAL EVENTS

02/23/2006
BUSINESS DISCONTINUED: NUI Corporation (NUI) was acquired by AGL Resources Inc, Atlanta, GA on November 30, 2004 for approximately $825 million, including the assumption of $709 million in debt. In 2005, AGL consolidated a number of NUI's business technology platforms into its enterprise-wide systems, including the accounting, payroll, human resources and supply chain functions. AGL also consolidated the former NUI utility call center operations into its own centralized call center. The combination of systems integration and the application of its operational model to managing NUI has resulted in significant improvements in its operations, as measured by the various metrics used to manage its business.

In 2004, AGL repaid $500 million outstanding under NUI's credit facility. Upon the repayment of the outstanding amounts, AGL terminated NUI's credit facility.

BAC000004

All future inquiries should be directed to AGL Resources Inc, DUNS #93-395-6211.

SUMMARY ANALYSIS

D&B Rating:NQ

The NQ rating stands for Not Quoted. This is generally assigned when a business has been confirmed as no longer active at the location, or when D&B is unable to confirm active operations. It may also appear on some branch reports, when the branch is located in the same city as the headquarters. For more information, see the D&B Rating Key.

CUSTOMER SERVICE

If you have questions about this report, please call our Customer Resource Center at 1.800.234.3867 from anywhere within the U.S. If you are outside the U.S. contact your local D&B office.

*** Additional Decision Support Available ***

Additional D&B products, monitoring services and specialized investigations are available to help you evaluate this company or its industry. Call Dun & Bradstreet's Customer Resource Center at 1.800.234.3867 from anywhere within the U.S. or visit our website at www.dnb.com.

CORPORATE FAMILY

Click below to buy a Business Information Report on that family member.
For an expanded, more current corporate family view, use D&B's Global Family Linkage product.

Parent:

Agl Resources Inc.	Atlanta, GA	DUNS # 93-395-6211

BUSINESS REGISTRATION

CORPORATE AND BUSINESS REGISTRATIONS PROVIDED BY MANAGEMENT OR OTHER SOURCE

The Corporate Details provided below may have been submitted by the management of the subject business and may not have been verified with the government agency which records such data.

Registered Name:	NUI Corporation
Business type:	CORPORATION
Corporation type:	PROFIT
Date incorporated:	FEB 03 2000
State of incorporation:	NEW JERSEY
Filing date:	FEB 03 2000
Status:	ACTIVE
Where filed:	DEPT OF STATE, TRENTON, NJ

SIC & NAICS

SIC:

Based on information in our file, D&B has assigned this company an extended 8-digit SIC. D&B's use of 8-digit SICs enables us to be more specific to a company's operations than if we use the standard 4-digit code.

The 4-digit SIC numbers link to the description on the Occupational Safety & Health Administration (OSHA)

NAICS:
221210 Natural Gas Distribution

Web site. Links open in a new browser window.

49320000 Gas and other services combined

PAYMENTS

D&B has not received a sufficient sample of payment experiences to establish a PAYDEX score.

D&B receives nearly 400 million payment experiences each year. We enter these new and updated experiences into D&B Reports as this information is received. At this time, none of those experiences relate to this company.

BANKING & FINANCE

D&B has researched this company and found no information available at this time.

PUBLIC FILINGS

The following Public Filing data is for information purposes only and is not the official record. Certified copies can only be obtained from the official source.

SUITS

Status:	**Settled**
DOCKET NO.:	L 001549 05
Plaintiff:	ELISA TAVAREZ
Defendant:	NUI CORPORATION AND OTHERS
Cause:	CONTRACT
Where filed:	MIDDLESEX COUNTY SUPERIOR COURT, NEW BRUNSWICK, NJ
Date status attained:	08/25/2006
Date filed:	02/25/2005
Latest Info Received:	11/27/2006

Suit amount:	**$118,674**
Status:	**Pending**
DOCKET NO.:	L 001592 04
Plaintiff:	LAWRENCE PARK INDUSTRIAL
Defendant:	NUI CORPORATION
Cause:	CONTRACT
Where filed:	SOMERSET COUNTY SUPERIOR COURT, SOMERVILLE, NJ
Date status attained:	10/28/2004
Date filed:	10/28/2004
Latest Info Received:	04/26/2005

Status:	**Change of venue granted**
DOCKET NO.:	L 001300 04
Plaintiff:	GREEN MEADOWS PARTNERS
Defendant:	NUI CORPORATION AND OTHERS
Where filed:	SOMERSET COUNTY SUPERIOR COURT, SOMERVILLE, NJ
Date status attained:	10/28/2004
Date filed:	09/02/2004
Latest Info Received:	01/04/2006

Suit amount:	**$4,568**
Status:	**Dismissal with prejudice**
DOCKET NO.:	DC-000669-2004
Plaintiff:	SEYFARTH SHAW
Defendant:	NUI CORPORATION
Cause:	CONTRC-REG
Where filed:	SOMERSET COUNTY SPECIAL CIVIL/SMALL CLAIMS COURT, SOMERVILLE, NJ

Date status attained: 04/29/2004
Date filed: 02/09/2004
Latest Info Received: 11/22/2004

Status: **Pending**
DOCKET NO.: L 000721 04
Plaintiff: RIDGEWOOD CORPORATION
Defendant: N U I CORPORATION AND OTHERS
Cause: TORT - OTHER
Where filed: MIDDLESEX COUNTY SUPERIOR COURT, NEW BRUNSWICK, NJ

Date status attained: 02/03/2004
Date filed: 02/03/2004
Latest Info Received: 12/14/2005

Status: **Dismissed**
DOCKET NO.: L 006804 03
Plaintiff: SMITH LAUNDERETTE INC
Defendant: NUI CORPORATION AND OTHERS
Cause: TORT - OTHER
Where filed: MIDDLESEX COUNTY SUPERIOR COURT, NEW BRUNSWICK, NJ

Date status attained: 10/21/2005
Date filed: 09/11/2003
Latest Info Received: 05/30/2006

Status: **Settled**
DOCKET NO.: L 001137 03
Plaintiff: JOCELYN STAEBLER
Defendant: NUI CORPORATION AND OTHERS
Cause: CONTRACT - EMPLOYMENT
Where filed: SOMERSET COUNTY SUPERIOR COURT, SOMERVILLE, NJ

Date status attained: 03/28/2006
Date filed: 08/18/2003
Latest Info Received: 04/24/2006

Status: **Dismissed**
DOCKET NO.: L 003770 03
Plaintiff: HARTFORD INS COMPANYMIDWEST
Defendant: NUI CORPORATION AND OTHERS
Cause: TORT - OTHER
Where filed: MIDDLESEX COUNTY SUPERIOR COURT, NEW BRUNSWICK, NJ

Date status attained: 10/20/2005
Date filed: 05/19/2003
Latest Info Received: 05/30/2006

Status: **Dismissed**
DOCKET NO.: L 000495 03
Plaintiff: BUYERZONE COM
Defendant: NUI CORPORATION AND OTHERS
Cause: BOOK ACCOUNT
Where filed: SOMERSET COUNTY SUPERIOR COURT, SOMERVILLE, NJ

Date status attained: 09/15/2003
Date filed: 04/10/2003
Latest Info Received: 03/16/2006

If it is indicated that there are defendants other than the report subject, the lawsuit may be an action to clear title to property and does not necessarily imply a claim for money against the subject.

UCC FILINGS

Collateral: All Assets
Type: Original
Sec. party: FLEET NATIONAL BANK, BOSTON, MA

Debtor: NUI CORPORATION
Filing number: 22649508
Filed with: SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ

Date filed: 10/28/2004
Latest Info Received: 12/02/2004

Collateral: Account(s) and proceeds
Type: Original
Sec. party: CREDIT SUISSE FIRST BOSTON, ACTING THROUGH ITS CAYMAN ISLANDS BRANCH, AS COLLATERAL AGENT, NEW YORK, NY
Debtor: NUI CORPORATION
Filing number: 21904738
Filed with: SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ

Date filed: 11/25/2003
Latest Info Received: 12/15/2003

Collateral: Leased Assets - Leased Business machinery/equipment
Type: Original
Sec. party: CANON FINANCIAL SERVICES, INC., MT. LAUREL, NJ
Debtor: NUI CORPORATION and OTHERS
Filing number: 21229343
Filed with: SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ

Date filed: 09/18/2002
Latest Info Received: 10/23/2002

Collateral: Leased Computer equipment and proceeds
Type: Original
Sec. party: LONGSHORE SYSTEMS, INC., WESTPORT, CT
Assignee: RELATIONAL, LLC, ROLLING MEADOWS, IL
Debtor: NUI CORPORATION, UNION, NJ
Filing number: 22508423
Filed with: SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ

Date filed: 08/04/2004
Latest Info Received: 08/24/2004

Collateral: Leased Equipment
Type: Original
Sec. party: ICX CORPORATION, CLEVELAND, OH
Debtor: NUI CORPORATION
Filing number: 21050053
Filed with: SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ

Date filed: 05/28/2002
Latest Info Received: 06/20/2002

Collateral: Leased Equipment
Type: Original
Sec. party: ICX CORPORATION, CLEVELAND, OH
Debtor: NUI CORPORATION, INC.
Filing number: 20911195
Filed with: SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ

Date filed: 03/07/2002
Latest Info Received: 04/01/2002

The public record items contained in this report may have been paid, terminated, vacated or released prior to the date this report was printed.

■ Investor Relations

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NYSE: ATG $37.08 +0.14
Nov 30 2007 10:50AM ET

Quick Facts

Company Profile

Headquarters: Atlanta
Employees: 2,385
Customers Served: 2.2 million
Ticker Symbol: ATG (NYSE)
Newspaper Listing: AGL Res

AGL Resources
We are a Fortune 1000 energy services holding company whose principal business is the distribution of natural gas in six states – Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. Our utilities serve more than 2.2 million customers, making us the largest natural gas distributor in the Southeast and mid-Atlantic regions, based on customer count.

We are also involved in various related businesses, including retail natural gas marketing to end-use customers in Georgia; natural gas asset management and related logistics activities for our own utilities as well as for other non-affiliated companies; natural gas storage arbitrage and related activities; operation of high-deliverability underground natural gas storage assets, and construction and operation of telecommunications conduit and fiber infrastructure within selected metropolitan areas.

Our business is organized into four operating segments:

Distribution Operations

- Natural gas local distribution companies construct, manage and maintain natural gas pipelines and distribution facilities in six states. Our distribution companies include: **Atlanta Gas Light**, **Chattanooga Gas**, **Elizabethtown Gas**, **Elkton Gas**, **Florida City Gas** and **Virginia Natural Gas**

Retail Energy Operations

- **SouthStar Energy Services** - Energy retail marketing company (a joint venture 70 percent owned by AGL Resources and 30 percent by Piedmont Natural Gas Co.) Markets natural gas and related services on an unregulated basis, principally to more than 530,000 customers in Georgia under the brand name **Georgia Natural Gas**

Wholesale Energy Services

- Wholly owned subsidiary **Sequent Energy Management** is involved in asset optimization, transportation, storage, producer and peaking services and wholesale marketing.

Energy Investments

- **Pivotal Jefferson Island Storage & Hub** – Wholly owned subsidiary operates a high-deliverability salt-dome natural gas storage cavern in Louisiana, approximately 10 miles from the Henry Hub.
- **AGL Networks** - Wholly owned subsidiary designs, builds and manages dark fiber optic networks in Atlanta and Phoenix, offering customers "last mile" connectivity between telecommunication service providers and business customers.
- **Pivotal Propane of Virginia** – Wholly owned subsidiary that serves the natural gas peaking needs of customers in our Virginia Natural Gas service area.

Executive Team

Name	Title
John W. Somerhalder II	Chairman, President and Chief Executive Officer
Bryan Batson	Senior VP, External Affairs
Jeffrey P. Brown	VP and Associate General Counsel
Ralph Cleveland	Senior VP, Engineering and Operations
Andrew W. Evans	Exec. VP, Chief Financial Officer
Jodi Gidley	Senior VP, Mid-Atlantic Operations and President, Elizabethtown Gas, Elkton Gas and Virginia Natural Gas
Dana A. Grams	President, Pivotal Energy Development
Kristin R. Kirkconnell	SVP, Information Services and Technology
Ronald L. Lepionka	VP, Chief Auditor
Hank Linginfelter	Executive Vice President, Utility Operations

Kevin P. Madden	Exec. VP, External Affairs
Melanie M. Platt	Senior VP, Human Resources and President, AGL Resources Foundation
Douglas N. Schantz	President, Sequent Energy Management
Bryan E. Seas, CPA	VP, Controller and Chief Accounting Officer
Paul R. Shlanta	Exec. VP. General Counsel and Chief Ethics and Compliance Officer
Suzanne Sitherwood	Senior VP, Southern Operations and President, Atlanta Gas Light & Chattanooga Gas
Brett Stovern	Vice President and Treasurer

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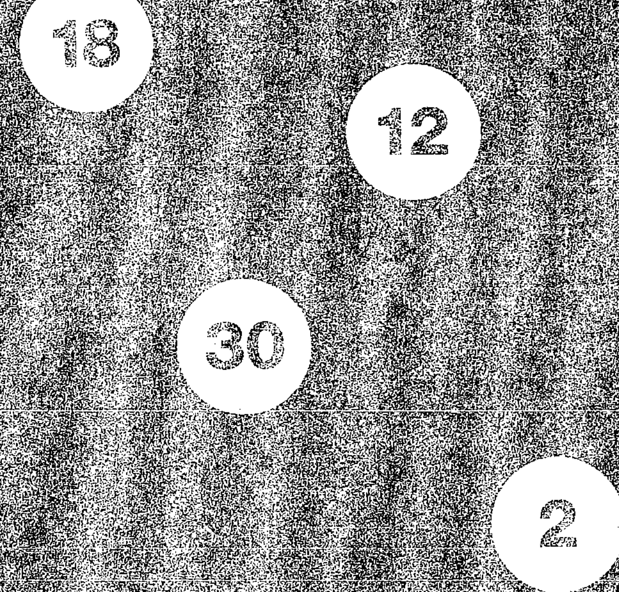
We sweat the small stuff.

AGL Resources 2006 Annual Report

BAC000006



About AGL Resources

AGL Resources serves more than 2.2 million natural gas customers in six states through its utility subsidiaries. We provide asset management and related services to wholesale natural gas customers across the United States through our subsidiary Sequent Energy Management. We market natural gas to customers in Georgia under the Georgia Natural Gas brand through a 70% ownership in SouthStar Energy Services. We own and operate other energy investments, among them Jefferson Island Storage & Hub, a high-deliverability natural gas storage facility near the Henry Hub in Louisiana.

00:18 Minutes potentially saved daily by home-basing employees, which eliminates nonproductive travel time to and from service centers

00:12 Minutes saved by preassembling complete truck kits and setting up conveniently located restock locations

00:30 Minutes saved by using technology to enhance route efficiencies and personnel logistics

2 Additional customers potentially served each day as a result of these time savings

Numbers shown are per field service employee per day, for an average workday at an Atlanta area service center, taken from a sample month.

Most of the time, it's all small stuff.

AGL Resources has demonstrated its ability to make disciplined acquisitions and successfully integrate them. We have built a solid platform for growth by focusing on execution every day. We sweat the small stuff to produce cost savings and bring new operations up to our superior level of customer service and profitability. In 2006, these efforts at our utilities, and the growth of our nonregulated businesses, generated record profits for the sixth straight year.

While we continue to seek opportunities to grow our business by acquiring new assets, we remain intensely focused on optimizing those we already own. So in 2006, we sought alternative opportunities in our own backyards. We'd already found the hours that could be taken out of our processes. Last year we found minutes to save, as in the examples at left. Through these kinds of improved field service efficiencies and contained operating costs, we have set the stage for new growth in our utilities in 2007.

Now's the time to sweat the growth stuff.

The yellow dot at left takes up about 1% of the page, yet it gets your full attention.

Our focus on finding every opportunity to reduce costs while improving operations has made AGL Resources one of the most efficient natural gas distributors in the country. In a difficult business environment that included high gas costs and the lingering effects of hurricanes, AGL Resources has had remarkable success at controlling costs. Now we're turning that kind of attention to the other side of the ledger.

In 2007, we're looking to increase our customer base by 1.2%. That may seem a small aspiration, but with more than 2.2 million customers the results will be substantial. Every new customer we add or retain represents potential profit. Maintaining our focus on controlling costs means this new revenue will flow to the bottom line.

John W. Jones
Executive Vice President
Tivoli Properties, Inc.
Atlanta, Georgia

» "**They call it a vertical main for a vertical neighborhood.** I call it a money saver that adds sizzle to our condominiums. There are some 7,000 multi-family units coming on the market in Atlanta this year. So when AGL Resources came to me with the idea of running gas lines vertically inside the core of our building, I was all for it. Now I can easily and inexpensively offer amenities like gas fireplaces, tankless water heaters and gas cooking to add value to my units. That's what my customers want, so it's what I need," said John W. Jones, executive vice president of Tivoli Properties.

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Growth in our service territories will come from new construction, conversions and customer retention. In 2006, Atlanta Gas Light began the vertical main initiative and began signing contracts with condominium developers. In 2007, this growth effort will be introduced in Virginia and Florida. In all our markets, we will increase marketing to create a preference for natural gas. Customers who convert to natural gas from other fuel types provide a long-term, stable account base with the potential for multi-appliance gas application.

In Georgia, our SouthStar joint venture is the leading natural gas marketer with over 35% of total market share. This means that for every 100 new gas customers in Georgia, we would expect to see two benefits – connecting those customers to our utility system and signing up 35 of those customers with SouthStar. And our customers benefit from our competitive natural gas rate plans that have consistently been among the lowest in the state. Our experience with SouthStar in Georgia has given us a strong platform of deregulated experience that we are using as we expand to other states that are implementing competitive markets for natural gas.

» **"I was eight months pregnant when Hurricane Wilma hit.** We lost power for two weeks. As mayor of Hialeah, my husband works whenever there is an emergency, and I don't know when he'll be home. Now that we've installed a natural gas–powered generator, I feel safer when I'm alone with my children. I know that if we lose power our security system will still work, we'll have hot water and lights, and I can stay informed by listening to the TV or radio," said Raiza Robaina. Connecting three families like the Robainas per business day may seem like a small accomplishment. But if these families see that connection as a lifeline, we just might have customers for life.

We acquired Florida City Gas and Elizabethtown Gas (in New Jersey) in our successful NUI acquisition. While some growth comes from new construction, conversions help drive these two markets. In New Jersey, we are successfully converting customers from heating oil to gas, and these conversions are up 100% since our acquisition of NUI. In our Florida markets, sales of gas generators for the residential market remain very strong in the wake of the past several hurricane seasons.

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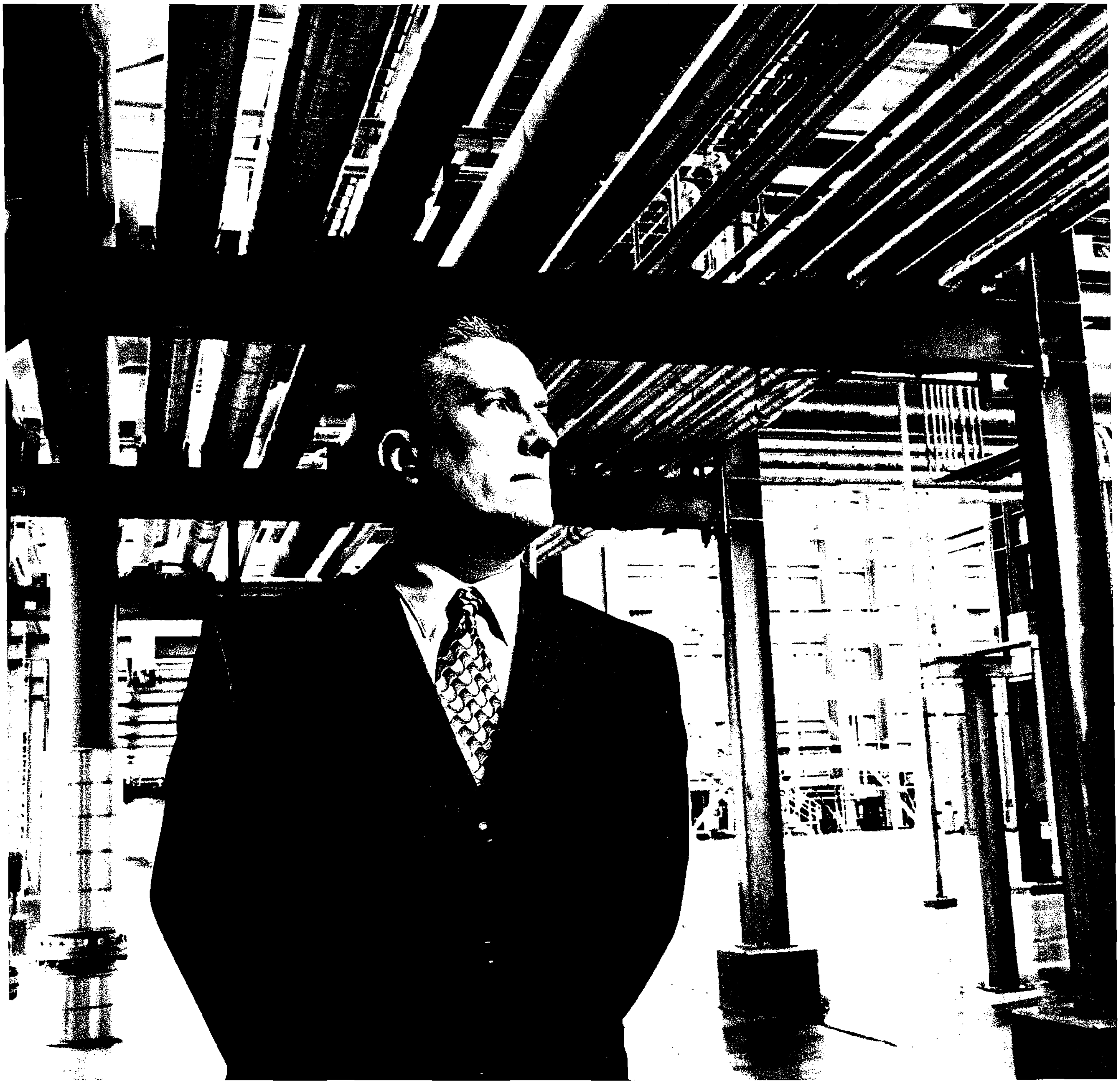
In Virginia we continue to leverage all our best practices. Last year, state regulators passed Virginia's first-ever performance-based rate plan for a natural gas company, freezing VNG's customer rates for five years. We are building a new supply pipeline to service our Virginia territory, and we will introduce the vertical main concept in the growing Norfolk area.

We convert former propane and electric heat customers, and add generator hookups in coastal areas. Successful marketing to these customer groups, combined with cost containment, will help deliver real growth in customer count and operating margin.

Raiza Robaina
Customer, Florida City Gas
Hialeah, Florida

James H. Sweeney
Senior Vice President,
Energy Management
KGen Power Management
Houston, Texas



» **"Sequent Energy Management delivers.** KGen Power Management owns a power plant in Dalton, Georgia. We selected Sequent to provide the natural gas our plant runs on because they were the only one of several bidders to offer a custom-fit solution under a pricing structure that fit our needs. Their flexibility was key. When there are supply or deliverability constraints, Sequent finds ways to address them. They go the extra mile when we need it the most, offering immediate support when the unexpected happens. Because Sequent kept meeting our needs during the hurricanes of 2005, KGen continued to supply Georgia Power with electricity, which was critical for its customers," said James H. Sweeney of KGen.

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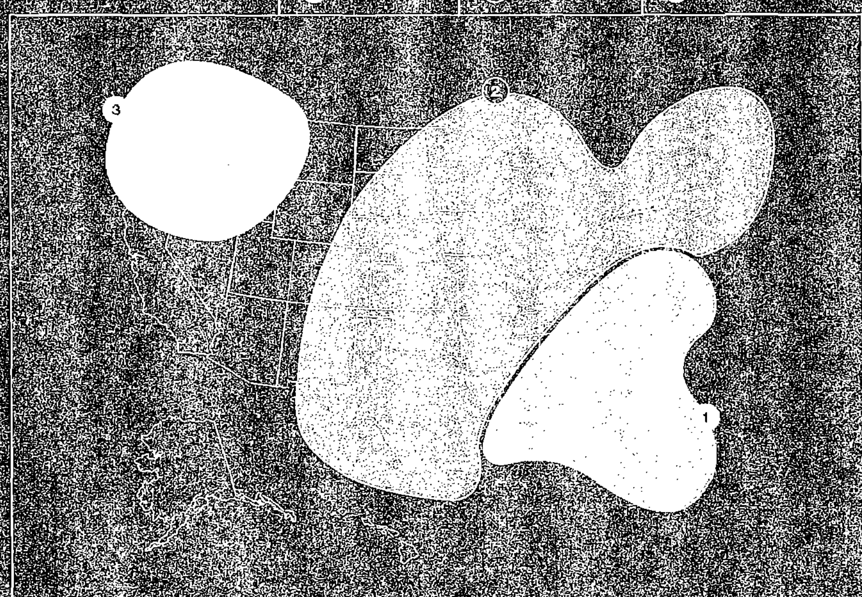
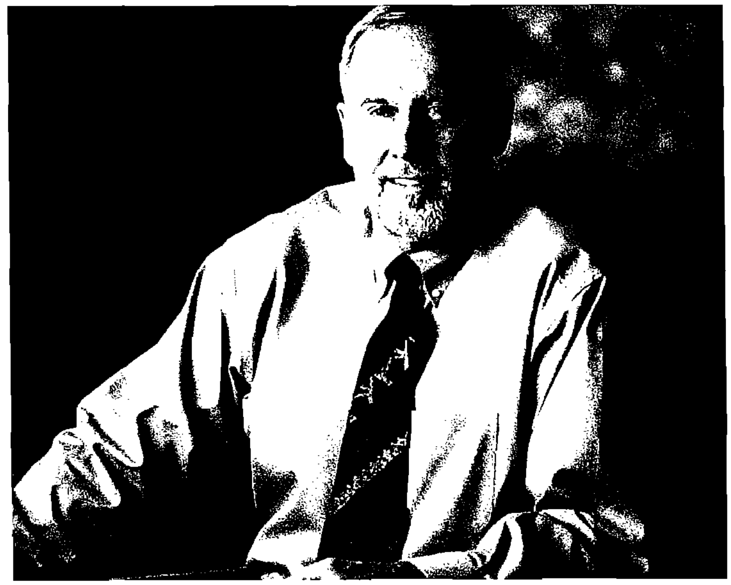
Sequent contributed $90 million to earnings before interest and taxes (EBIT) in 2006. Improved opportunities to capture storage margins and expansion drove growth at this unregulated subsidiary. Sequent now serves three more states in the northwestern United States, signing up the largest gas distributor in Idaho and expanding services into Washington and Oregon. In 2006, Sequent also added new producer services in Louisiana, west-to-east transport capacity and a major new fuel supply power generation client in New York City. Sequent increased its salt storage portfolio and also extended its asset management program in Georgia another two years.

Pivotal Energy Development, our Houston-based business development unit, announced plans in December 2006 to build a natural gas storage facility in a salt dome in Beaumont, Texas. Construction should start in 2008 with operations to begin in 2010.

Sequent Expansion Chart | 1 2001–2002 | 2 2003–2005 | 3 2006





» To Our Shareholders

When I joined the company a year ago, many people asked what major changes I planned to make to the company's operations and strategic direction. What I found was a company with an exceptionally strong leadership team, a sound business strategy, and a solid track record of performance and execution—essentially, a company that didn't need major, sweeping changes.

Our portfolio contains a good mix of businesses, with earnings balanced between our regulated and nonregulated operations. Our nonutility companies complement our core regulated utility franchises, providing effective diversification for our earnings. Together, our businesses helped us achieve another year of record results in 2006: earnings of $2.73 per share, a 9% increase over the previous year. Our utility businesses did a great job reducing expenses, but were challenged from a margin perspective by unprecedented warm weather. Our nonutility businesses turned in strong financial performances—further demonstrating how investors benefit from our diversified participation in key segments of the natural gas value chain.

Our 2006 earnings clearly illustrate that our current strategy creates shareholder value while meeting the needs of customers. We continue to strengthen our balance sheet and cash flow generation. This provides the financial flexibility to reward shareholders. As evidence of our success, the Board voted to increase the dividend by 11% in January 2007, to an annual level of $1.64 per share. Throughout 2006, our stock price hit several all-time highs and finished the year near those record levels. This shows investors have confidence in our ability to execute on our strategy.

Although I do not expect major strategic changes, we will continue to adapt to market dynamics and serve our growing customer base. We will increasingly sweat the small stuff. Sometimes the best paybacks come from what seem like smaller opportunities. A few minutes saved here and there can lead to substantial savings across the company when multiplying the incremental value by 2.2 million customers. While we remain committed to growing our business through strategic and reasonably priced acquisitions, we are equally committed to finding new ways to add revenue directly to the bottom line.

On the following pages, key leaders of our company discuss various business challenges. We have a proven record of quality execution and we continue to focus on delivering the value that you, our shareholders, have come to expect.

Management changes, particularly at the top, can be unsettling to some investors—especially when a company has a history of strong leadership and stability. I am fortunate to have joined a company where nearly all of the leadership team remains intact and focused on producing results. We have one of the most dedicated and capable workforces anywhere in the country. We have the right people—executing the right strategy—to help us build on the company's historical success. We intend to continue to be an excellent steward of your investment in AGL Resources. Thank you for your confidence.

John W. Somerhalder II
President and Chief Executive Officer
February 12, 2007

» Questions and Answers

What is your assessment of the company's performance in 2006 and its prospects for 2007 and beyond?
SOMERHALDER » We overcame several challenges in 2006 to produce strong earnings results and to position the company well for future growth. Our distribution business performed very well in the face of margin pressure caused by the warmest weather on record and customer conservation. By focusing on controlling operation and maintenance costs at each utility, we offset lower operating margins and actually grew earnings in the distribution business, protecting our customer count through strong marketing efforts. Our retail marketing business provided stable yet strong earnings and began expanding its business model into other deregulating markets. Our wholesale business had an exceptional year, driven by volatility in the natural gas markets and a growing customer base. We clearly did not make as much progress on our natural gas storage strategy as I would have liked, primarily because the state of Louisiana challenged our mineral lease and delayed expansion of the Jefferson Island storage facility. We will continue working toward a settlement to enable that project to move forward; in the meantime, we have announced the development of a significant storage project in Texas that will be an important part of our portfolio. Taken collectively, all of these efforts position us well for 2007 and the years ahead in terms of growing earnings and providing value to our shareholders.

With the successful integration of the NUI utility assets, will Distribution Operations focus on acquiring additional utility assets or on organic growth from existing franchises?
MARTINEZ » We will continue to be opportunistic around acquisitions that fit our business model, particularly now that we can integrate utilities into our unified technology platforms, rapidly achieving the associated cost savings to benefit shareholders. We also will take advantage of organic growth possibilities through continued customer "win-back" and conversion efforts begun in 2006. You've read about our successes: converting nongas customers in New Jersey; building customer retention and new-customer loyalty with gas generators in our hurricane-threatened territories; and opening new prospects in high-rise construction in Georgia. These are growth opportunities that travel well to other markets. We've always had new-customer growth, but this growth has been offset by customer turn-offs due to redevelopment or relocation. Our goal is to decrease these losses and capture a larger percentage of new-customer growth through our expanded marketing efforts. Retaining customers and growing the number of customers on existing mains is less costly than adding new customers through investments in infrastructure.

Warmer-than-normal weather and the resulting lower customer usage had a significant impact on utility earnings in 2006. How did this affect AGL Resources?
MARTINEZ » Our earnings were affected, but the impact was limited to about 1 percent of our reported operating margin. Regulatory mechanisms help us mitigate a substantial portion of the weather impact for the majority of our customers. We have weather-normalization adjustments approved in our New Jersey, Virginia and Tennessee jurisdictions, which offset most, but not all, of the impact of warmer weather. In Georgia, our largest service area, we have essentially decoupled (or separated) the fixed costs of operating the gas distribution system from the cost the customer pays for the gas itself. The bottom line is weather definitely impacts our operating margin, but we will continue to pursue ways to substantially mitigate our weather risk.

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2006 AGL Resources Policy Committee

Andrew W. Evans
Executive Vice President,
Chief Financial Officer

R. Eric Martinez, Jr.
Executive Vice President,
Utility Operations

Sequent has been a critical part of the company's growth strategy for several years. Will you continue to grow in terms of size (relative to the overall company), assets under management and geographic market reach?

SCHANTZ » Sequent expects to contribute 10% to 15% of AGL Resources' annual EBIT in a normal year. We will continue in that range, except in periods of dramatic market volatility. We have several initiatives to build customer relationships, broaden our capabilities and expand into other attractive geographic markets. Last year we made significant asset management transactions in the northwestern United States, providing us an entry point into the Canadian gas market as well. And during 2006, we signed several asset management agreements to serve a growing customer base in the eastern United States. We also added Gulf Coast salt cavern storage capacity and west-to-east transportation capacity to serve customers in our largest market. Greater transportation and storage capacity is the key to gaining the flexibility needed to serve more markets and expand our scope of business, including value-added services to small- and mid-cap producers in moving their gas into the marketplace.

What opportunities do you see to expand in the natural gas storage market, particularly in the Gulf Coast?

MADDEN » We believe the announced capacity of incremental storage could more than double and still not meet anticipated demand. The addition of rapid-cycle, high-deliverability storage lags behind growth of the overall gas market.

The need for storage is largely driven by increasing demand for natural gas–fired electricity generation. According to the Energy Information Administration, peak electric demand in the United States is projected to increase 30% to 40% over the next five years. Most of this demand will be filled by natural gas–fired generation. Other factors driving the need for storage include the shift in domestic production from Gulf of Mexico wells to the Rockies and central United States; expected increases in liquefied natural gas (LNG) deliveries; and the growing need for "peaking gas" to support the nation's economy through extreme weather.

AGL Resources is well positioned, through Pivotal Energy Development, to continue to acquire and build rapid-cycle, high-deliverability storage facilities. Jefferson Island is the only storage facility connected directly to the Henry Hub. Our Golden Triangle Storage development project, announced in December 2006, is well positioned to meet the needs created by imported LNG. We continue to seek opportunities to grow strategically in the natural gas storage market.

In recent years, we've seen a dramatic improvement in the company's balance sheet strength and its cash flow generation. What does the cash flow picture look like in 2007 and beyond? In terms of deploying free cash, should investors expect to see higher dividends, share repurchases or reinvestment in the business?

EVANS » We expect to generate funds from operations in excess of capital expenditures over the next few years. Our balance sheet strength and improved cash flow generation have provided us the flexibility to reward shareholders through a combination of dividend growth, share repurchases and investment in business growth. We have increased our dividend five times over the last four years, and our last increase signaled to the market that we are migrating toward a dividend payout ratio comparable to the average of our peer group of companies. We implemented a share repurchase program in 2006, primarily to offset the dilutive effect of

Kevin P. Madden
Executive Vice President,
External Affairs

Douglas N. Schantz
President,
Sequent Energy
Management

Melanie M. Platt
Senior Vice President,
Human Resources

Paul R. Shlanta
Executive Vice President,
General Counsel and
Chief Ethics and Compliance Officer

John W. Somerhalder II
President and
Chief Executive Officer

share issuances each year under our long-term incentive and director compensation plans. We also continue to reinvest capital in the business when we identify projects that offer returns in excess of our cost of capital and support our strategy for long-term growth.

SouthStar has consistently performed well and contributed significantly to AGL Resources' earnings growth. Are there any plans to grow SouthStar's market share or geographic reach?

EVANS » SouthStar has contributed on average about 15% of our annual EBIT over the past few years. The business has been remarkably stable and successful in a deregulated market, primarily through efficient management practices and a highly effective marketing strategy. We operate the business in conjunction with a very good partner, Piedmont Natural Gas, and our focus has been to market SouthStar's services to a quality customer base in terms of credit profile and natural gas usage patterns, while keeping bad debt expense (as a percent of total revenue) as low as possible. SouthStar's focus on a highly targeted and selective market has helped maintain a stable market share in Georgia of about 35%, which we do not expect will change materially in the near future. The real opportunity is to export the successful model we have built in Georgia to other markets that are in the early stages of natural gas deregulation, as we have done recently by moving into the Ohio and Florida markets. We also are exploring opportunities to expand SouthStar's retail focus to include a larger portion of the commercial and industrial market that might benefit from our services.

We continue to hear media reports about corporate governance issues such as stock-option backdating, and the costs of Sarbanes-Oxley compliance. Have any of these issues changed the way you think about corporate governance and compliance issues?

SHLANTA » We have strong policies and procedures in place to help ensure that the problems that have occurred at other companies do not occur here. For example, a 2006 review of our stock-option granting practices confirmed that our program has been implemented consistently with no procedural irregularities—and no backdating issues. To continue to enhance our culture of compliance, we are using ongoing training programs to make ethical, compliant behavior second nature to every employee. That's the best way to keep these types of issues from harming our company and our shareholders.

Are you seeing any signs of a "war for talent" as companies compete for a diminishing pool of skilled employees?

PLATT » We're working proactively to ensure AGL Resources has a diverse pool of talented, skilled employees for our future needs. In our utilities, we are working with trade and technical colleges and university engineering programs to identify potential employees already trained in safety, reliability and technical issues. To meet expanding competition and maintain our low-risk business model, Sequent is working with universities and aggressively recruiting experienced personnel by offering a holistic compensation package with the flexible, portable benefits that younger workers demand.

To attract and retain the best employees, we must offer competitive benefits, an opportunity to grow professionally and develop a career, a work/life balance, and recognition for high performance and community service. Our business goals align with our community service, and both are supported by our social responsibility values and the "generosity of spirit" that is part of our employee culture. (For more on our community service and corporate giving, please turn to page 119.)

AGL Resources Operations at a Glance

Distribution Operations

Atlanta Gas Light is the largest natural gas distributor in the Southeast in terms of customers, serving 237 communities in the state of Georgia. It provides gas delivery service to more than 1.5 million residential, commercial and industrial customers and delivers approximately 211 billion cubic feet (Bcf) of gas annually. It owns and operates more than 30,000 miles of pipeline* and three liquefied natural gas (LNG) plants.

Chattanooga Gas provides retail natural gas sales and transportation services to approximately 61,000 residential, commercial and industrial customers in Hamilton County and Bradley County, Tennessee. Chattanooga Gas delivers approximately 15 Bcf of gas annually. It also owns and operates more than 1,500 miles of pipeline and one LNG plant.

Elizabethtown Gas provides natural gas service to approximately 269,000 residential, commercial and industrial customers in northwestern and east central New Jersey. It delivers approximately 46 Bcf of gas annually through more than 3,000 miles of pipeline.

Elkton Gas provides natural gas service to approximately 6,000 residential, commercial and industrial customers in northeastern Maryland. Elkton Gas delivers approximately 1 Bcf of gas annually through more than 87 miles of pipeline.

Florida City Gas provides natural gas service to approximately 104,000 residential, commercial and industrial customers in southeastern and east central Florida. It delivers approximately 9 Bcf of gas annually through more than 3,200 miles of pipeline.

Virginia Natural Gas provides natural gas service to more than 264,000 residential, commercial and industrial customers in southeastern Virginia. It delivers approximately 33 Bcf of gas annually through more than 5,200 miles of pipeline. It also owns and operates a 156-mile high-pressure, large-diameter transmission pipeline serving major wholesale customers.

Retail Energy Operations

SouthStar Energy Services is a joint venture operating in Georgia under the trade name Georgia Natural Gas. The business supplies natural gas to more than 533,000 retail and commercial customers in Georgia and to over 270 industrial customers throughout the Southeast, and provides gas supply to a large utility in Ohio.

Wholesale Services

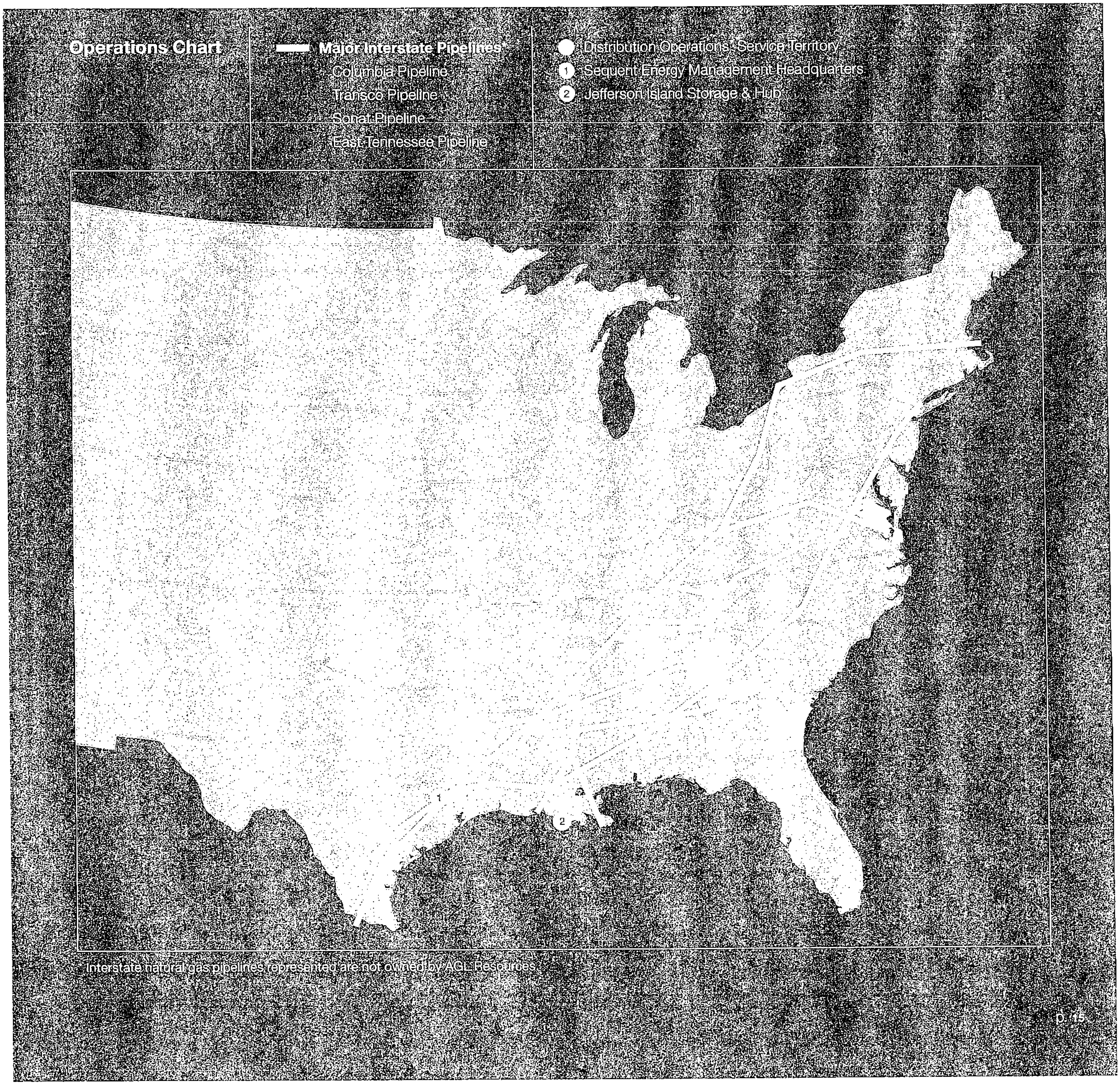
Sequent Energy Management provides customers throughout the United States the ability to optimize their natural gas asset portfolio and increase cost effectiveness from wellhead to burner tip. Services include natural gas asset management, producer and storage services, and full-requirements supply, including peaking needs.

Energy Investments

The company operates **Jefferson Island Storage & Hub**, a high-deliverability natural gas storage facility in Louisiana. The facility consists of two salt dome storage caverns with 10 Bcf of total capacity and about 7 Bcf of working gas capacity. In addition, the company manages the operation of Pivotal Propane of Virginia, a peaking facility in northern Virginia.

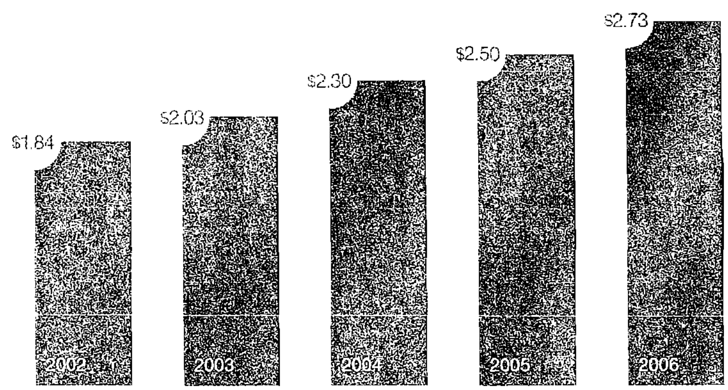
AGL Networks is a carrier-neutral provider that leases telecommunications fiber to a variety of customers in the Atlanta, Georgia and Phoenix, Arizona metropolitan areas. AGL Networks provides conduit and dark fiber to its customers under long-term lease arrangements, as well as telecommunications construction services.

* Defined for each utility as "distribution and transportation pipelines" with delivered gas amounts shown for 2006.

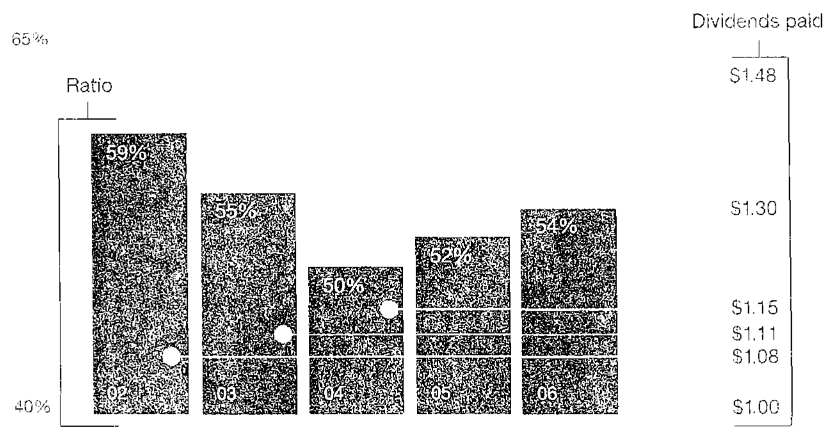


*Interstate natural gas pipelines represented are not owned by AGL Resources.

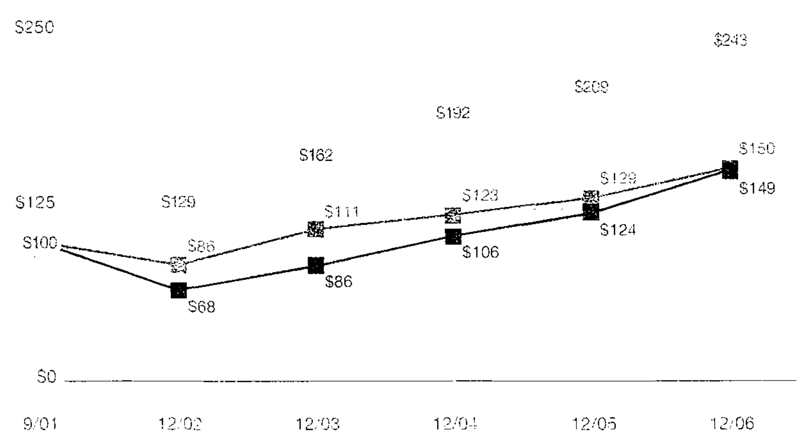
Financial Charts



Calendar year basic earnings per share.



AGL Resources remains focused on maintaining a competitive dividend yield and a payout ratio approaching the average of our peer group of utilities. In February 2007, the company announced an 11% dividend increase to a new annual dividend rate of $1.64 per share.



63-month cumulative total return
$100 invested on 9/30/01 in stock or index, including reinvestment of dividends, for fiscal years ending December 31.

AGL Resources
S&P 500 Index
S&P Utilities Index

Source: Research Data Group

United States
Securities and Exchange Commission
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2006

OR

☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from to .

Commission File Number 1-14174

AGL RESOURCES INC.

Exact name of registrant as specified in its charter

Georgia	58-2210952
State or other jurisdiction of incorporation or organization	I.R.S. Employer Identification No
Ten Peachtree Place NE, Atlanta, Georgia 30309	404-584-4000
Address and zip code of principal executive offices	Registrant's telephone number, including area code

Securities registered pursuant to Section 12(b) of the Act:

Title of Class	Name of each exchange on which registered
Common Stock, $5 Par Value	New York Stock Exchange
8% Trust Preferred Securities	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 under the Securities Act. Yes [X] No [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Act. Yes [ ] No [X]

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer.

Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes [ ] No [X]

The aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates of the registrant, computed by reference to the price at which the registrant's common stock was last sold as of the last business day of the registrant's most recently completed second fiscal quarter, was $2,971,414,431.

The number of shares of the registrant's common stock outstanding as of January 31, 2007 was 77,752,515.

Documents incorporated by reference:

Portions of the Proxy Statement for the 2007 Annual Meeting of Shareholders ("Proxy Statement") to be held May 2, 2007, are incorporated by reference in Part III.

Table of Contents

Glossary of Key Terms

Atlanta Gas Light » Atlanta Gas Light Company

AGL Capital » AGL Capital Corporation

AGL Networks » AGL Networks, LLC

Bcf » Billion cubic feet

Chattanooga Gas » Chattanooga Gas Company

Credit Facility » Credit agreement supporting our commercial paper program

Deregulation Act » 1997 Natural Gas Competition and Deregulation Act

Dominion Ohio » Dominion East of Ohio, a Cleveland, Ohio based natural gas company; a subsidiary of Dominion Resources, Inc.

EBIT » Earnings before interest and taxes, a non-GAAP measure that includes operating income, other income, equity in SouthStar's income, minority interest in SouthStar's earnings, donations and gain on sales of assets and excludes interest and tax expense; as an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, operating income or net income as determined in accordance with GAAP

Energy Act » Energy Policy Act of 2005

ERC » Environmental remediation costs

FASB » Financial Accounting Standards Board

FERC » Federal Energy Regulatory Commission

Florida Commission » Florida Public Service Commission

GAAP » Accounting principles generally accepted in the United States of America

Georgia Commission » Georgia Public Service Commission

LNG » Liquefied natural gas

LOCOM » Lower of weighted average cost or current market price

Maryland Commission » Maryland Public Service Commission

Marketers » Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission

Medium-term notes » Notes issued by Atlanta Gas Light with scheduled maturities between 2012 and 2027 bearing interest rates ranging from 6.6% to 9.1%

MGP » Manufactured gas plant

New Jersey Commission » New Jersey Board of Public Utilities

NYMEX » New York Mercantile Exchange, Inc.

OCI » Other comprehensive income

Operating margin » A non-GAAP measure of income, calculated as revenues minus cost of gas, that excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain or loss on the sale of our assets; these items are included in our calculation of operating income as reflected in our statements of consolidated income. Operating margin should not be considered an alternative to, or more meaningful than, operating income or net income as determined in accordance with GAAP

Jefferson Island » Jefferson Island Storage & Hub, LLC

Piedmont » Piedmont Natural Gas

Pivotal Propane » Pivotal Propane of Virginia, Inc.

Pivotal Utility » Pivotal Utility Holdings, Inc., doing business as Elizabethtown Gas, Elkton Gas and Florida City Gas

PGA » Purchased gas adjustment

PRP » Pipeline replacement program

SEC » Securities and Exchange Commission

Sequent » Sequent Energy Management, L.P.

SFAS » Statement of Financial Accounting Standards

SouthStar » SouthStar Energy Services LLC

Tennessee Commission » Tennessee Regulatory Authority

Virginia Natural Gas » Virginia Natural Gas, Inc.

Virginia Commission » Virginia State Corporation Commission

Referenced Accounting Standards

APB 25 » APB Opinion No. 25, "Accounting for Stock Issued to Employees"

EITF 98-10 » Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities"

EITF 99-02 » EITF Issue No. 99-02, "Accounting for Weather Derivatives"

EITF 02-03 » EITF Issue No. 02-03, "Issues Involved in Accounting for Contracts under EITF Issue No. 98-10, 'Accounting for Contracts Involved in Energy Trading and Risk Management Activities'"

EITF 06-3 » EITF Issue No. 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statements"

FIN 46 & FIN 46R » FASB Interpretation No. (FIN) 46, "Consolidation of Variable Interest Entities"

FIN 47 » FIN 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143"

FIN 48 » FIN 48, "Accounting for Uncertainty in Income Taxes, an interpretation of SFAS Statement No. 109"

SFAS 5 » Statement of Financial Accounting Standards (SFAS) No. 5, "Accounting for Contingencies"

SFAS 13 » SFAS No. 13, "Accounting for Leases"

SFAS 71 » SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"

SFAS 87 » SFAS No. 87, "Employers' Accounting for Pensions"

SFAS 106 » SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"

SFAS 109 » SFAS No. 109, "Accounting for Income Taxes"

SFAS 123 & SFAS 123R » SFAS No. 123, "Accounting for Stock-Based Compensation"

SFAS 131 » SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information"

SFAS 133 » SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"

SFAS 141 » SFAS No. 141, "Business Combinations"

SFAS 142 » SFAS No. 142, "Goodwill and Other Intangible Assets"

SFAS 148 » SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure"

SFAS 149 » SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"

SFAS 154 » SFAS No. 154, "Accounting Changes and Error Corrections"

SFAS 157 » SFAS No. 157, "Fair Value Measurements"

SFAS 158 » SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans"

Part I

Item 1 » Business

Nature of Our Business

Unless the context requires otherwise, references to "we," "us," "our," the "company," and "AGL Resources" are intended to mean consolidated AGL Resources Inc. and its subsidiaries.

We are a Fortune 1000 energy services holding company whose principal business is the distribution of natural gas in six states—Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. We generate nearly all our operating revenues through the sale, distribution, transportation and storage of natural gas. Our six utilities serve more than 2.2 million end-use customers, making us the largest distributor of natural gas in the southeastern and mid-Atlantic regions of the United States based on customer count. We are involved in several related and complementary businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for each of our utilities as well as for nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability natural gas storage assets. We also own and operate a small telecommunications business that constructs and operates conduit and fiber infrastructure within select metropolitan areas.

We manage these businesses through four operating segments, as described below, and a nonoperating corporate segment.

Distribution Operations » The distribution operations segment is the largest component of our business and includes utilities in six states—Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. These utilities are subject to regulation and oversight by state agencies in each state that we serve. These agencies approve natural gas rates designed to provide us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our fixed and variable costs such as depreciation, interest, maintenance and overhead costs. These agencies also are charged with establishing mechanisms by which our utilities can earn a reasonable return for our shareholders.

With the exception of our Atlanta Gas Light Company (Atlanta Gas Light) subsidiary in Georgia, earnings in our Distribution Operations segment can be affected by customer consumption patterns that are a function of weather conditions and price levels for natural gas. Atlanta Gas Light charges rates to its customers primarily as monthly fixed charges. Our non-Georgia jurisdictions have various regulatory mechanisms to provide us with a reasonable opportunity to recover our costs, but they are not direct offsets to the potential impacts on earnings of weather and customer consumption.

Retail Energy Operations » Our retail energy operations segment consists of SouthStar Energy Services LLC (SouthStar), the largest marketer of natural gas in Georgia. SouthStar's operations also are sensitive to customer consumption patterns similar to those affecting our utility operations. SouthStar uses a variety of hedging strategies, such as futures, options, swaps, weather derivative instruments and other risk management tools, to mitigate the potential effect of these issues on its operations.

Wholesale Services » Our wholesale services segment, which consists of Sequent Energy Management, L.P. (Sequent), takes advantage of arbitrage opportunities within the gas supply, storage and transportation markets to generate earnings, and its profitability is correlated to volatility in these markets. Market volatility results from a number of factors, such as weather fluctuations or the change in supply of, or demand for, natural gas in different regions of the country. Sequent seeks to capture value from the price disparity among geographic locations and various time horizons created by this volatility. In doing so, Sequent also seeks to mitigate the risks associated with this volatility and protect its margin through a variety of risk management and hedging activities.

Energy Investments » Our energy investments segment includes a number of businesses that are related and complementary to our primary business. The most significant of these businesses is our natural gas storage business, which develops, acquires and operates high-deliverability salt-dome storage assets in the Gulf Coast region of the United States. While this business also can generate additional revenue during times of peak market demand for natural gas storage services, the majority of our storage services are covered under medium- to long-term contracts at a fixed market rate.

For additional information on our segments, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Results of Operations" and Note 11, "Segment Information," set forth in Item 8, "Financial Statements and Supplementary Data." Operating revenues, operating margin and earnings before interest and taxes (EBIT) for each of our segments are presented in the following table for the years ended December 31, 2006, 2005 and 2004.

In millions	Operating revenues	Operating margin[1]	EBIT[1]
2006			
Distribution operations	$1,624	$ 807	$310
Retail energy operations	930	156	63
Wholesale services	182	139	90
Energy investments	41	36	10
Corporate[2]	(156)	1	(9)
Consolidated	$2,621	$1,139	$464
2005			
Distribution operations	$1,753	$ 814	$299
Retail energy operations	996	146	63
Wholesale services	95	92	49
Energy investments	56	40	19
Corporate[2]	(182)	–	(11)
Consolidated	$2,718	$1,092	$419
2004			
Distribution operations	$1,111	$ 640	$247
Retail energy operations	827	132	52
Wholesale services	54	53	24
Energy investments	25	13	7
Corporate[2]	(185)	(1)	(16)
Consolidated	$1,832	$ 837	$314

[1] These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

[2] Includes the elimination of intercompany revenues and intercompany cost of gas.

In 2006, we derived approximately 80% of our EBIT from our regulated natural gas distribution business and the sale of natural gas to end-use customers primarily in Georgia through SouthStar. This statistic is significant because it represents the portion of our earnings that directly results from the underlying business of supplying natural gas to retail customers. Although SouthStar is not subject to the same regulatory framework as our utilities, it is an integral part of the retail framework for providing gas service to end-use customers in the state of Georgia.

The remaining 20% of our EBIT was principally derived from businesses that are complementary to our natural gas distribution business. We engage in natural gas asset management and the operation of high-deliverability natural gas underground storage as ancillary activities to our utility franchises. These businesses allow us to be opportunistic in capturing incremental value at the wholesale level, provide us with deepened business insight about natural gas market dynamics and facilitate our ability, in the case of asset management, to provide transparency to regulators as to how that value can be captured to benefit our utility customers through profit-sharing arrangements. Given the volatile and changing nature of the natural gas resource base in North America and globally, we believe that participation in these related businesses strengthens our business.

Natural Gas Demand

During 2006 we experienced a decline in per-household natural gas use, resulting in operating margin erosion. This decline was largely due to warmer weather—which was on average 14% warmer than in the prior year based on heating degree days—and higher-than-historical natural gas prices. The higher natural gas prices resulted in an average 34% increase in our residential customers' natural gas bills. The higher prices were primarily the result of market concerns about the sufficiency of the supply of natural gas due to disruptions in the availability of natural gas supplies caused by hurricanes Katrina and Rita in 2005. Additionally, our underlying business of supplying natural gas to retail customers continues to be negatively impacted by the addition of newer, more energy-efficient housing and efficiency improvements in natural gas appliances. The decline in natural gas usage has been somewhat offset by the growing trend toward larger homes that require more energy to heat despite the use of more efficient appliances.

In 2006, these factors contributed to lower volumes of natural gas deliveries to our customers as a result of customer conservation from the combination of both warmer weather and the reaction to the high prices for natural gas. The higher natural gas prices also resulted in higher bad debt expense. These factors negatively affected our EBIT.

Natural gas prices as of January 1, 2007 were approximately 44% lower than the same date in 2006 and are expected to be lower during the remainder of the current heating season (January–March). To the extent these lower natural gas prices are reflected in lower natural gas prices to our customers, the impact of conservation experienced during the prior heating season may be lessened. Additionally, the lower prices could result in a return to normalized consumption and a return to normalized bad debt expense. If this occurs, we would expect that our operating margins and EBIT would be positively impacted relative to what we experienced in the November 2005 through March 2006 heating season.

Seasonality

The operating revenues and EBIT of our distribution operations, retail energy operations and wholesale services segments are seasonal. During the heating season, natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather than in periods of warmer weather. Approximately 66% of these segments' operating revenues and 68% of these segments' EBIT for the year ended December 31, 2006 were generated during the five-month heating season and are reflected in our statements of consolidated income for the quarters ended March 31, 2006, and December 31, 2006. Our base operating expenses, excluding cost of gas, interest expense and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, our operating results vary significantly from quarter to quarter as a result of seasonality. Seasonality also affects the comparison of certain balance sheet items such as receivables, unbilled revenue, inventories and short-term debt across quarters. However, these items are comparable when reviewing our annual results.

Available Information

Detailed information about us is contained in our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other reports, and amendments to those reports, that we file with or furnish to the Securities and Exchange Commission (SEC). These reports are available free of charge at our website, www.aglresources.com, as soon as reasonably practicable after we electronically file such reports with or furnish such reports to the SEC. We will furnish copies of such reports free of charge upon written request to our Investor Relations department. You can contact our Investor Relations department at:

AGL Resources Inc.
Investor Relations—Dept. 1071
P.O. Box 4569
Atlanta, GA 30309-4569
404-584-3801

In Part III of this Form 10-K, we incorporate by reference certain information from our Proxy Statement for our 2007 annual meeting of shareholders. We expect to file that Proxy Statement with the SEC on or about March 19, 2007, and we will promptly make it available on our website. Please refer to the Proxy Statement when it is available.

Additionally, our corporate governance guidelines, code of ethics, code of business conduct and the charters of each of our Board of Directors committees are available on our website. We will furnish copies of such information free of charge upon written request to our Investor Relations department.

Item 1a » Risk Factors

Cautionary Statement Regarding Forward-looking Statements

Certain expectations and projections regarding our future performance referenced in this report, in other materials we file with the SEC or otherwise release to the public, and on our website are forward-looking statements. Senior officers may also make verbal statements to analysts, investors, regulators, the media and others that are forward-looking. Forward-looking statements involve matters that are not historical facts, such as statements in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere regarding our future operations, prospects, strategies, financial condition, economic performance (including growth and earnings), industry conditions and demand for our products and services. We have tried, whenever possible, to identify these statements by using words such as "anticipate," "assume," "believe," "can," "could," "estimate," "expect," "forecast," "future," "goal," "indicate," "intend," "may," "outlook," "plan," "potential," "predict," "project," "seek," "should," "target," "will," "would" and similar expressions.

You are cautioned not to place undue reliance on our forward-looking statements. Our forward-looking statements are not guarantees of future performance and are based on currently available competitive, financial and economic data along with our operating plans. While we believe that our expectations for the future are reasonable in view of the currently available information, our expectations are subject to future events, risks and inherent uncertainties, as well as potentially inaccurate assumptions, and there are numerous factors—many beyond our control—that could cause results to differ significantly from our expectations. Such events, risks and uncertainties include, but are not limited to those set forth below and in the other documents that we file with the SEC. We note these factors for investors as permitted by the Private Securities Litigation Reform Act of 1995. There also may be other factors that we cannot anticipate or that are not described in this report, generally because we do not perceive them to be material, that could cause results to differ significantly from our expectations.

Forward-looking statements are only as of the date they are made, and we do not undertake any obligation to update these statements to reflect subsequent circumstances or events. You are advised, however, to review any further disclosures we make on related subjects in our Form 10-Q and Form 8-K reports to the SEC.

Risks Related to Our Business

Risks related to the regulation of our businesses could affect the rates we are able to charge, our costs and our profitability. Our businesses are subject to regulation by federal, state and local regulatory authorities. In particular, at the federal level our distribution businesses are regulated by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005 (Energy Act). At the state level, our distribution businesses are regulated by the Georgia Public Service Commission (Georgia Commission), the Tennessee Regulatory Authority (Tennessee Commission), the New Jersey Board of Public Utilities (New Jersey Commission), the Florida Public Service Commission (Florida Commission), the Virginia State Corporation Commission (Virginia Commission) and the Maryland Public Service Commission (Maryland Commission). These authorities regulate many aspects of our distribution operations, including construction and maintenance of facilities, operations, safety, rates that we charge customers, rates of return, the authorized cost of capital, recovery of pipeline replacement and environmental remediation costs, relationships with our affiliates, and carrying costs we charge marketers selling retail natural gas in Georgia and certificated by the Georgia Commission (Marketers) for gas held in storage for their customer accounts. Our ability to obtain rate increases and rate supplements to maintain our current rates of return depends on regulatory discretion, and there can be no assurance that we will be able to obtain rate increases or rate supplements or continue receiving our currently authorized rates of return.

Deregulation in the natural gas industry is the separation of the provision and pricing of local distribution gas services into discrete components. Deregulation typically focuses on the separation of the gas distribution business from the gas sales business and is intended to cause the opening of the formerly regulated sales business to alternative unregulated suppliers of gas sales services.

In 1997, the Georgia legislature enacted the Natural Gas Competition and Deregulation Act (Deregulation Act). To date, Georgia is the only state in the nation that has fully deregulated gas distribution operations, which ultimately resulted in Atlanta Gas Light exiting the retail natural gas sales business while retaining its gas distribution operations. Marketers then assumed the retail gas sales responsibility at deregulated prices. The deregulation process required Atlanta Gas Light to completely reorganize its operations and personnel at significant expense. It is possible that the legislature could reverse the deregulation process and require or permit Atlanta Gas Light to provide retail gas sales service once again or require our retail energy operations segment, SouthStar, to change the nature of how it provides natural gas to certain customers. In addition, the Georgia Commission has statutory authority on an emergency basis to order Atlanta Gas Light to temporarily provide the same retail gas service that it provided prior to deregulation. If any of these events were to occur, we would incur costs to reverse the restructuring process or potentially lose the earnings opportunity embedded within the current marketing framework. Furthermore, the Georgia Commission has authority to change the terms under which we charge Marketers for certain supply-related services, which could also affect our future earnings.

A significant portion of our accounts receivable are subject to collection risks, due in part to a concentration of credit risk in Georgia and at Sequent.
We have an accounts receivable collection risk in Georgia due to a concentration of credit risk related to the provision of natural gas services to Marketers. At September 30, 1998 (prior to deregulation), Atlanta Gas Light had approximately 1.5 million end-use customers in Georgia. In contrast, at December 31, 2006, Atlanta Gas Light had only 11 certificated and active Marketers in Georgia, four of which (based on customer count and including SouthStar) accounted for approximately 36% of our consolidated operating margin for 2006. As a result, Atlanta Gas Light now depends on a concentrated number of customers for revenues. The failure of these Marketers to pay Atlanta Gas Light could adversely affect Atlanta Gas Light's business and results of operations and expose it to difficulties in collecting Atlanta Gas Light's accounts receivable. The provisions of Atlanta Gas Light's tariff allow it to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill. Additionally, SouthStar markets directly to end-use customers and has periodically experienced credit losses as a result of severe cold weather or high prices for natural gas that increase customers' bills and, consequently, impair a customers' ability to pay.

Sequent often extends credit to its counterparties. Despite performing credit analyses prior to extending credit and seeking to effectuate netting agreements, Sequent is exposed to the risk that it may not be able to collect amounts owed to it. If the counterparty to such a transaction fails to perform and any collateral Sequent has secured is inadequate, Sequent could experience material financial losses. Further, Sequent has a concentration of credit risk which could subject a significant portion of its credit exposure to collection risks. Approximately 57% of Sequent's credit exposure is concentrated in 20 counterparties. Although most of this concentration is with counterparties that are either load-serving utilities or end-use customers and that have supplied some level of credit support, default by any of these counterparties in their obligations to pay amounts due Sequent could result in credit losses that would negatively impact our wholesale services segment.

We face increasing competition, and if we are unable to compete effectively, our revenues, operating results and financial condition will be adversely affected and may limit our ability to grow our business.

The natural gas business is highly competitive, and we are facing increasing competition from other companies that supply energy, including electric companies, oil and propane providers and, in some cases, energy marketing and trading companies. In particular, the success of our investment in SouthStar is affected by the competition SouthStar faces from other energy marketers providing retail natural gas services in the Southeast. Natural gas competes with other forms of energy. The primary competitive factor is price. Changes in the price or availability of natural gas relative to other forms of energy and the ability of end-users to convert to alternative fuels affect the demand for natural gas. In the case of commercial, industrial and agricultural customers, adverse economic conditions, including higher gas costs, could also cause these customers to bypass or disconnect from our systems in favor of special competitive contracts with lower per-unit costs.

Our wholesale services segment competes with national and regional full-service energy providers, energy merchants and producers and pipelines for sales based on our ability to aggregate competitively priced commodities with transportation and storage capacity. Some of our competitors are larger and better capitalized than we are and have more national and global exposure than we do. The consolidation of this industry and the pricing to gain market share may affect our margins. We expect this trend to continue in the near term, and the increasing competition for asset management deals could result in downward pressure on the volume of transactions and the related margins available in this portion of Sequent's business.

The asset management arrangements between Sequent and our local distribution companies, and between Sequent and its nonaffiliated customers, may not be renewed or may be renewed at lower levels, which could have a significant impact on Sequent's business.

Sequent currently manages the storage and transportation assets of our affiliates Atlanta Gas Light, Elizabethtown Gas, Elkton Gas, Virginia Natural Gas, Inc. (Virginia Natural Gas), Florida City Gas and Chattanooga Gas Company (Chattanooga Gas) and shares profits it earns from the management of those assets with those customers and their respective customers, except at Elizabethtown Gas and Elkton Gas where Sequent is assessed an annual fixed fee of approximately $4 million payable in monthly installments. Entry into and renewal of these agreements are subject to regulatory approval. In addition, Sequent has asset management agreements with certain nonaffiliated customers. Sequent's results could be significantly impacted if these agreements are not renewed or are amended or renewed with less favorable terms.

Our infrastructure improvement and customer growth may be restricted by the capital-intensive nature of our business.

We must construct additions to our natural gas distribution system to continue the expansion of our customer base. We may also need to construct expansions of our existing natural gas storage facilities or develop and construct new natural gas storage facilities. The cost of this construction may be affected by the cost of obtaining government approvals, development project delays or unexpected changes in project costs. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost, and projected construction schedule and completion timeline of a project. Our cash flows may not be fully adequate to finance the cost of this construction. As a result, we may be required to fund a portion of our cash needs through borrowings or the issuance of common stock, or both. For our distribution operations segment, this may limit our ability to expand our infrastructure to connect new customers due to limits on the amount we can economically invest, which shifts costs to potential customers and may make it uneconomical for them to connect to our distribution systems. For our natural gas storage business, this may significantly reduce our earnings and return on investment from what would be expected for this business, or may impair our ability to complete the expansions or development projects.

Changes in weather conditions may affect our earnings.

Weather conditions and other natural phenomena can have a large impact on our earnings. Severe weather conditions can impact our suppliers and the pipelines that deliver gas to our distribution system. Extended mild weather, during either the winter period or summer period, can have a significant impact on demand for and cost of natural gas.

We have a weather normalization adjustment (WNA) mechanism for Elizabethtown Gas and Chattanooga Gas that partially offsets the impact of unusually cold or warm weather on residential and commercial customer billings and margin. Additionally, Virginia

Natural Gas has a WNA mechanism for its residential customers that partially offsets the impact of unusually cold or warm weather. The WNA is most effective in a reasonable temperature range relative to normal weather using historical averages. The protection afforded by the WNA depends on continued regulatory approval. The loss of this continued regulatory approval could make us more susceptible to weather-related earnings fluctuations.

Changes in weather conditions may also impact SouthStar's earnings. As a result, SouthStar uses a variety of weather derivative instruments to mitigate the impact on its margins in the event of warmer-than-normal weather in the winter months. However, these instruments do not fully protect SouthStar's earnings from the effects of unusually warm weather.

Our business is subject to environmental regulation in all jurisdictions in which we operate, and our costs to comply are significant. Any changes in existing environmental regulation could negatively affect our results of operations and financial condition.

Our operations and properties are subject to extensive environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. Such environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances into the environment. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Our current costs to comply with these laws and regulations are significant to our results of operations and financial condition. Failure to comply with these laws and regulations and failure to obtain any required permits and licenses may expose us to fines, penalties or interruptions in our operations that could be material to our results of operations.

In addition, claims against us under environmental laws and regulations could result in material costs and liabilities. Existing environmental regulations could also be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur. With the trend toward stricter standards, greater regulation, more extensive permit requirements and an increase in the number and types of assets operated by us subject to environmental regulation, our environmental expenditures could increase in the future, particularly if those costs are not fully recoverable from our customers. Additionally, the discovery of presently unknown environmental conditions could give rise to expenditures and liabilities, including fines or penalties, which could have a material adverse effect on our business, results of operations or financial condition.

We could incur additional material costs for the environmental condition of some of our assets, including former manufactured gas plants.

We are generally responsible for all on-site and certain off-site liabilities associated with the environmental condition of the natural gas assets that we have operated, acquired or developed, regardless of when the liabilities arose and whether they are or were known or unknown. In addition, in connection with certain acquisitions and sales of assets, we may obtain, or be required to provide, indemnification against certain environmental liabilities. Before natural gas was widely available, we manufactured gas from coal and other fuels. Those manufacturing operations were known as manufactured gas plants (MGP) which we ceased operating in the 1950s.

We have identified ten sites in Georgia and three in Florida where we own all or part of an MGP site. We are required to investigate possible environmental contamination at those MGP sites and, if necessary, clean up any contamination. As of December 31, 2006, the soil and sediment remediation program was complete for all Georgia sites, although groundwater cleanup continues. As of December 31, 2006, projected costs associated with the MGP sites were $27 million. For elements of the MGP program where we still cannot provide engineering cost estimates, considerable variability remains in future cost estimates.

In addition, we are associated with former sites in New Jersey, North Carolina and other states that we assumed with our acquisition of NUI Corporation (NUI) in November 2004. Material cleanups of these sites have not been completed nor are precise estimates available for future cleanup costs. For the New Jersey sites, cleanup cost estimates range from $60 million to $118 million. Costs have been estimated for only one of the non-New Jersey sites, for which current estimates range from $10 million to $17 million.

Our profitability may decline if the counterparties to Sequent's asset management transactions fail to perform in accordance with Sequent's agreements.

Sequent focuses on capturing the value from idle or underutilized energy assets, typically by executing transactions that balance the needs of various markets and time horizons. Sequent is exposed to the risk that counterparties to our transactions will not perform their obligations. Should the counterparties to these arrangements fail to perform, we might be forced to enter into alternative hedging arrangements, honor the underlying commitment at then-current market prices or return a significant portion of the consideration received for gas under a long-term contract. In such events, we might incur additional losses to the extent of amounts, if any, already paid to or received from counterparties.

We are exposed to market risk and may incur losses in wholesale services and retail energy operations.

The commodity, storage and transportation portfolios at Sequent and the commodity and storage portfolios at SouthStar consist of contracts to buy and sell natural gas commodities, including contracts that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate, we could experience financial losses from our trading activities. Value at risk (VaR) is defined as the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability. Based on a 95% confidence interval and employing a 1-day holding period for all positions. Sequent's and SouthStar's portfolio of positions as of December 31. 2006 had a 1-day holding period VaR of $1 million and $0.1 million, respectively.

Our accounting results may not be indicative of the risks we are taking or the economic results we expect for wholesale services.

Although Sequent enters into various contracts to hedge the value of our energy assets and operations, the timing of the recognition of profits or losses on the hedges does not always correspond to the profits or losses on the item being hedged. The difference in accounting can result in volatility in Sequent's reported results, even though the expected profit margin is essentially unchanged from the date the transactions were consummated.

Inflation and increased gas costs could adversely impact our ability to control operating expenses, increase our level of indebtedness and adversely impact our customer base.

Inflation has caused increases in certain operating expenses which have required us to replace assets at higher costs. We attempt to control costs in part through implementation of best practices and business process improvements, many of which are facilitated through investments in information systems and technology. We have a process in place to continually review the adequacy of our utility gas rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those gas rates. Historically, we have been able to budget and control operating expenses and investments within the amounts authorized to be collected in rates. and we intend to continue to do so. However. any inability by us to reasonably control our expenses would adversely influence our future results.

Rapid increases in the price of purchased gas cause us to experience a significant increase in short-term debt because we must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our utility collection efforts as customers are more likely to delay the payment of their gas bills. leading to higher-than-normal accounts receivable. This situation results in higher short-term debt levels and increased bad debt expense. Should the price of purchased gas increase significantly during the upcoming heating season, we would expect increases in our short-term debt, accounts receivable and bad debt expense during 2007.

Finally, higher costs of natural gas in recent years have already caused many of our utility customers to conserve in the use of our gas services and could lead to even more customers utilizing such conservation methods or switching to other more efficient competing products. The higher costs have also allowed competition from products utilizing alternative energy sources for applications that have traditionally used natural gas, encouraging some customers to move away from natural gas–fired equipment to equipment fueled by other energy sources.

A decrease in the availability of adequate pipeline transportation capacity could reduce our revenues and profits.

Our gas supply depends on the availability of adequate pipeline transportation and storage capacity. We purchase a substantial portion of our gas supply from interstate sources. Interstate pipeline companies transport the gas to our system. A decrease in interstate pipeline capacity available to us or an increase in competition for interstate pipeline transportation and storage service could reduce our normal interstate supply of gas.

The cost of providing pension and postretirement health care benefits to eligible employees and qualified retirees is subject to changes in pension fund values and changing demographics and may have a material adverse effect on our financial results.

We have a defined benefit pension plan for the benefit of substantially all full-time employees and qualified retirees. The cost of providing these benefits to eligible current and former employees is subject to changes in the market value of our pension fund assets and changing demographics, including longer life expectancy of beneficiaries and an expected increase in the number of eligible former employees over the next five years.

Any sustained declines in equity markets and reductions in bond yields may have a material adverse effect on the value of our pension funds. In these circumstances, we may be required to recognize an increased pension expense or a charge to our statement of consolidated income to the extent that the pension fund values are less than the total anticipated liability under the plans.

Transporting and storing natural gas involves numerous risks that may result in accidents and other operating risks and costs.
Our gas distribution activities involve a variety of inherent hazards and operating risks, such as leaks, accidents and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution and impairment of our operations, which in turn could lead to substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The location of pipelines and storage facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect our financial position and results of operations.

Natural disasters, terrorist activities and the potential for military and other actions could adversely affect our businesses.
Natural disasters may damage our assets. The threat of terrorism and the impact of retaliatory military and other action by the United States and its allies may lead to increased political, economic and financial market instability and volatility in the price of natural gas that could affect our operations. In addition, future acts of terrorism could be directed against companies operating in the United States, and companies in the energy industry may face a heightened risk of exposure to acts of terrorism. These developments have subjected our operations to increased risks. The insurance industry has also been disrupted by these events. As a result, the availability of insurance covering risks against which we and our competitors typically insure may be limited. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms.

Risks Related to Our Corporate and Financial Structure

We depend on our ability to successfully access the capital and financial markets. Any inability to access the capital or financial markets may limit our ability to execute our business plan or pursue improvements that we may rely on for future growth.
We rely on access to both short-term money markets (in the form of commercial paper and lines of credit) and long-term capital markets as a source of liquidity for capital and operating requirements not satisfied by the cash flow from our operations. If we are not able to access financial markets at competitive rates, our ability to implement our business plan and strategy will be affected. Certain market disruptions may increase our cost of borrowing or affect our ability to access one or more financial markets. Such market disruptions could result from;

- adverse economic conditions
- adverse general capital market conditions
- poor performance and health of the utility industry in general
- bankruptcy or financial distress of unrelated energy companies or Marketers
- significant decrease in the demand for natural gas
- adverse regulatory actions that affect our local gas distribution companies and our natural gas storage business
- terrorist attacks on our facilities or our suppliers
- extreme weather conditions

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.
We use derivatives, including futures, forwards and swaps, to manage our commodity and financial market risks. We could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could adversely affect the reported fair value of these contracts.

We are vulnerable to interest rate risk with respect to our debt, which could lead to changes in interest expense and adversely affect our earnings.
We are subject to interest rate risk in connection with the issuance of fixed-rate and variable-rate debt. In order to maintain our desired mix of fixed-rate and variable-rate debt, we use interest rate swap agreements and exchange fixed-rate and variable-rate interest payment obligations over the life of the arrangements, without exchange of the underlying principal amounts. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk." We cannot ensure that we will be successful in structuring such swap agreements to effectively manage our risks. If we are unable to do so, our earnings may be reduced. In addition, higher interest rates, all other things equal, reduce the earnings that we derive

from transactions where we capture the difference between authorized returns and short-term borrowings.

If we breach any of the financial covenants under our various credit facilities, our debt service obligations could be accelerated.
Our existing credit facility and the SouthStar line of credit contain financial covenants. If we breach any of the financial covenants under these agreements, our debt repayment obligations under them could be accelerated. In such event, we may not be able to refinance or repay all our indebtedness, which would result in a material adverse effect on our business, results of operations and financial condition.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all our outstanding obligations in the event of a default on our part.
Our credit agreement supporting our commercial paper program (Credit Facility) and our indentures under which our debt is issued contain cross-default provisions. Accordingly, should an event of default occur under some of our debt agreements, we face the prospect of being in default under other of our debt agreements, obliged in such instance to satisfy a large portion of our outstanding indebtedness and unable to satisfy all our outstanding obligations simultaneously.

A downgrade in our credit rating could negatively affect our ability to access capital.
Standard & Poor's Ratings Services (S&P), Moody's Investors Service (Moody's) and Fitch Ratings (Fitch) currently assign our senior unsecured debt a rating of BBB+, Baa1 and A-, respectively. Our commercial paper currently is rated A2, P2 and F2 by S&P, Moody's and Fitch, respectively. If the rating agencies downgrade our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources would likely decrease.

Additionally, if our credit rating by either S&P or Moody's falls to non-investment grade status, we will be required to provide additional support for certain customers of our wholesale business. As of December 31, 2006, if our credit rating had fallen below investment grade, we would have been required to provide collateral of approximately $10 million to continue conducting our wholesale services business with certain counterparties.

Item 1b » Unresolved Staff Comments

We do not have any unresolved comments from the SEC staff regarding our periodic or current reports under the Securities Exchange Act of 1934, as amended.

Item 2 » Properties

Distribution Operations » As of December 31, 2006, the properties of our distribution operations segment represented approximately 90% of the net property, plant and equipment in our consolidated balance sheet. This property primarily includes assets used for the distribution of natural gas to our customers in our service areas, including more than 43,000 miles of distribution and transmission mains. We have approximately 7.35 billion cubic feet (Bcf) of liquefied natural gas (LNG) storage capacity in five LNG plants located in Georgia, New Jersey and Tennessee. In addition, we own three propane storage facilities in Virginia and Georgia that have a combined storage capacity of approximately 4.5 million gallons. These LNG plants and propane facilities supplement the gas supply during peak usage periods.

Energy Investments » The properties in our energy investments segment are primarily investments that are complementary to our distribution operations or provide services consistent with our core enterprises, including a natural gas storage and hub facility in Louisiana located approximately eight miles from the Henry Hub. The Henry Hub is the largest centralized point for natural gas spot and futures trading in the United States. The New York Mercantile Exchange, Inc. (NYMEX) uses the Henry Hub as the point of delivery for its natural gas futures contracts. Many natural gas marketers also use the Henry Hub as their physical contract delivery point or their price benchmark for spot trades of natural gas. Our natural gas storage and hub facility consists of two salt-dome gas storage caverns with approximately 9.72 Bcf of total capacity and about 7.23 Bcf of working gas capacity. The facility has approximately 0.72 Bcf/day withdrawal capacity and 0.36 Bcf/day injection capacity. We completed a project during 2005 to expand compression capability, enabling us to increase the number of times a customer can inject and withdraw their total gas inventory annually from 10 to 12.

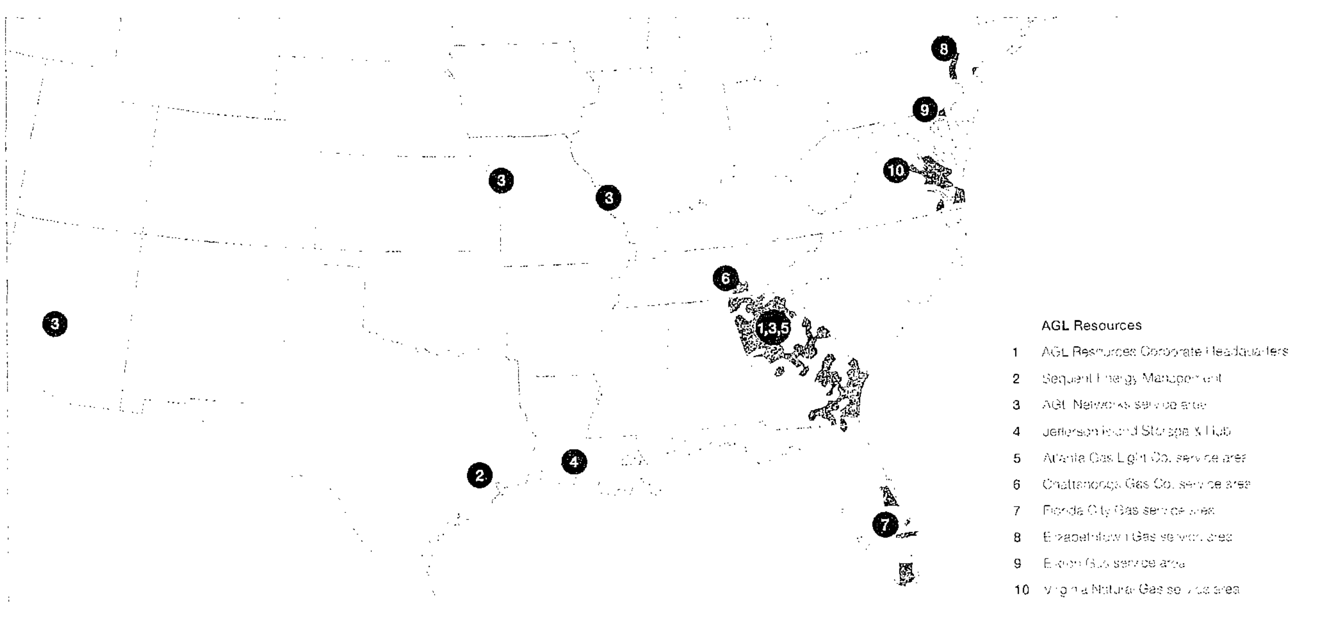
We also own a propane facility in Virginia. The propane facility provides our utility in Virginia with 0.03 Bcf of propane air per day on a 10-day per year basis. This system is important to our Virginia operations because it provides propane as a substitute for natural gas when natural gas demand is peaking.

In addition, energy investments' properties include telecommunications conduit and fiber in public rights-of-way that are leased to our customers primarily in Atlanta and Phoenix. This includes over 76,000 fiber miles, of which approximately 32% of our dark fiber in Atlanta and 24% of our dark fiber in Phoenix has been leased.

Retail Energy Operations, Wholesale Services and Corporate » The properties used at our retail energy operations, wholesale services and corporate segments consist primarily of leased and owned office space in Atlanta and Houston and their contents, including furniture and fixtures. The majority of our Atlanta-based employees are located at our corporate headquarters, a leased building with approximately 227,000 square feet of office space. In addition, our retail energy operations segment leases approximately 30,200 square feet at another office building in Atlanta. We lease approximately 32,000 square feet of office space for our employees in Houston.

We own or lease additional office, warehouse and other facilities throughout our operating areas. We consider our properties and the properties of our subsidiaries to be well maintained, in good operating condition and suitable for their intended purpose. We expect additional or substitute space to be available as needed to accommodate expansion of our operations.

Below is a map illustrating our total asset base and existing service territories as of December 31, 2006:



Item 3 » Legal Proceedings

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities. In addition, we are party, as both plaintiff and defendant, to a number of lawsuits related to our business on an ongoing basis. Management believes that the outcome of all regulatory proceedings and litigation in which we are currently involved will not have a material adverse effect on our consolidated financial condition or results of operations. Information regarding some of these proceedings is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Results of Operations" and in Note 8 to our consolidated financial statements under the caption "Litigation" set forth in Item 8, "Financial Statements and Supplementary Data."

Item 4 » Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of our security holders during the fourth quarter ended December 31, 2006.

Item 4a » Executive Officers of the Registrant

Set forth below are the names, ages and positions of our executive officers along with their business experience during the past five years. All officers serve at the discretion of our Board of Directors. All information is as of the date of the filing of this report.

Name, age and position with the Company	Periods served
John W. Somerhalder II, Age 51[1]	
President and Chief Executive Officer	March 2006–Present
Andrew W. Evans, Age 40[2]	
Executive Vice President and Chief Financial Officer	May 2006–Present
Senior Vice President and Chief Financial Officer	September 2005–May 2006
Vice President and Treasurer	April 2002–September 2005
Kevin P. Madden, Age 54	
Executive Vice President, External Affairs	November 2005–Present
Executive Vice President, Distribution and Pipeline Operations	April 2002–November 2005
Executive Vice President, Legal, Regulatory and Governmental Strategy	September 2001–April 2002
R. Eric Martinez, Jr., Age 38	
Executive Vice President, Utility Operations	November 2005–Present
Senior Vice President, Business Process Initiatives	August 2005–November 2005
Vice President and General Manager of Elizabethtown Gas	December 2004–August 2005
Senior Vice President, Engineering & Construction of Pivotal Energy Development	August 2003–December 2004
Chief Operating Officer of AGL Networks, LLC	December 2002–August 2003
Vice President and General Manager of AGL Networks, LLC	June 2002–December 2002
Vice President, Business Development	October 2000–June 2002
Paul R. Shlanta, Age 49	
Executive Vice President, General Counsel and Chief Ethics and Compliance Officer	September 2005–Present
Senior Vice President, General Counsel and Chief Corporate Compliance Officer	September 2002–September 2005
Senior Vice President, General Counsel and Corporate Secretary	July 2002–September 2002
Senior Vice President and General Counsel	September 1998–July 2002
Melanie M. Platt, Age 52	
Senior Vice President, Human Resources	September 2004–Present
Senior Vice President and Chief Administrative Officer	November 2002–September 2004
Vice President of Investor Relations	May 1998–November 2002
Vice President and Corporate Secretary	January 1995–June 2002
Douglas N. Schantz, Age 51[3]	
President, Sequent Energy Management, LP	May 2003–Present

[1] Mr. Somerhalder was executive vice president of El Paso Corporation (NYSE: EP) from 2000 until May 2005, and he continued service under a professional services agreement from May 2005 until March 2006.

[2] Mr. Evans was vice president of corporate development of Mirant Corporation's (NYSE: MIR) (formerly Southern Energy, Inc.) Mirant Americas business unit from June 2001 until April 2002.

[3] Mr. Schantz served as vice president of the gas origination division at Cinergy Marketing & Trading, LP, an affiliate of Cinergy Corp (NYSE: CIN), from September 2000 to April 2003.

Part II

Item 5 » Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Holders of Common Stock, Stock Price and Dividend Information

Our common stock is listed on the New York Stock Exchange under the symbol ATG. At January 31, 2007, there were 7,512 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2006 and 2005 is as follows:

	Sales price of common stock		Cash dividend per common share
Quarter ended	High	Low	
2006			
March 31, 2006	**$36.48**	**$34.40**	**$0.37**
June 30, 2006	**38.13**	**34.43**	**0.37**
September 30, 2006	**40.00**	**34.76**	**0.37**
December 31, 2006	**40.09**	**36.04**	**0.37**
2005			
March 31, 2005	$36.09	$32.00	$0.31
June 30, 2005	38.89	33.37	0.31
September 30, 2005	39.32	35.29	0.31
December 31, 2005	37.54	32.23	0.37

We have historically paid dividends to common shareholders four times a year: March 1, June 1, September 1 and December 1. We have paid 237 consecutive quarterly dividends beginning in 1948. Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. See Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Cash Flow from Financing Activities—Dividends on Common Stock." Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors, some of which are noted below. In certain cases, our ability to pay dividends to our common shareholders is limited by the following:

- our ability to satisfy our obligations under certain financing agreements, including debt-to-capitalization and total shareholders' equity covenants
- our ability to satisfy our obligations to any preferred shareholders

Under Georgia law, the payment of cash dividends to the holders of our common stock is limited to our legally available assets and subject to the prior payment of dividends on any outstanding shares of preferred stock. Our assets are not legally available for paying cash dividends if, after payment of the dividend:

- we could not pay our debts as they become due in the usual course of business, or
- our total assets would be less than our total liabilities plus, subject to some exceptions, any amounts necessary to satisfy (upon dissolution) the preferential rights of shareholders whose preferential rights are superior to those of the shareholders receiving the dividends

Issuer Purchases of Equity Securities

The following table sets forth information regarding purchases of our common stock by us and any affiliated purchasers during the three months ended December 31, 2006. Stock repurchases may be made in the open market or in private transactions at times and in amounts that we deem appropriate. However, there is no guarantee as to the exact number of additional shares that may be repurchased, and we may terminate or limit the stock repurchase program at any time. We will hold the repurchased shares as treasury shares.

Period	Total number of shares purchased[1,2,3]	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs[3]	Maximum number of shares that may yet be purchased under the publicly announced plans or programs[3]
October 2006	111,000	$37.02	109,100	7,160,400
November 2006	108,421	$37.74	105,000	7,055,400
December 2006	98,480	$39.10	82,900	6,972,500
Total fourth quarter	317,901	$37.92	297,000	

[1] The total number of shares purchased includes an aggregate of 8,400 shares surrendered to us to satisfy tax withholding obligations in connection with the vesting of shares of restricted stock and/or the exercise of stock options.

[2] On March 20, 2001, our Board of Directors approved the purchase of up to 600,000 shares of our common stock in the open market to be used for issuances under the Officer Incentive Plan (Officer Plan). We purchased 30,000 and 12,501 shares for such purposes in the third and fourth quarters of 2006, respectively. As of December 31, 2006, we had purchased a total 286,567 of the 600,000 shares authorized for purchase, leaving 313,433 shares available for purchase under this program.

[3] On February 3, 2006, we announced that our Board of Directors had authorized a plan to repurchase up to a total of 8 million shares of our common stock, excluding the shares remaining available for purchase in connection with the Officer Plan as described in note (2) above, over a five-year period.

The information required by this item regarding securities authorized for issuance under our equity compensation plans will be set forth under the caption "Executive Compensation–Equity Compensation Plan Information" in the Proxy Statement for our 2007 Annual Meeting of Shareholders or in a subsequent amendment to this report. All such information will be incorporated by reference from the Proxy Statement in Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" hereof or set forth in such amendment to this report.

Item 6 » Selected Financial Data

Selected financial data about AGL Resources is set forth in the table below. You should read the data in the table in conjunction with the consolidated financial statements and related notes set forth in Item 8, "Financial Statements and Supplementary Data."

Dollars and shares in millions, except per share amounts	2006	2005	2004	2003	2002
Income statement data					
Operating revenues	**$2,621**	$2,718	$1,832	$ 983	$ 877
Cost of gas	**1,482**	1,626	995	339	268
Operating margin[1]	**1,139**	1,092	837	644	609
Operating expenses					
Operation and maintenance	**473**	477	377	283	274
Depreciation and amortization	**138**	133	99	91	89
Taxes other than income taxes	**40**	40	29	28	29
Total operating expenses	**651**	650	505	402	392
Gain on sale of Caroline Street campus	**—**	—	—	16	—
Operating income	**488**	442	332	258	217
Equity in earnings of SouthStar Energy Services LLC	**—**	—	—	46	27
Other (expense) income	**(1)**	(1)	—	(6)	3
Minority interest	**(23)**	(22)	(18)	—	—
Earnings before interest and taxes (EBIT)[1]	**464**	419	314	298	247
Interest expense	**123**	109	71	75	86
Earnings before income taxes	**341**	310	243	223	161
Income taxes	**129**	117	90	87	58
Income before cumulative effect of change in accounting principle	**212**	193	153	136	103
Cumulative effect of change in accounting principle, net of $5 in income taxes	**—**	—	—	(8)	—
Net income	**$ 212**	$ 193	$ 153	$ 128	$ 103
Common stock data					
Weighted average shares outstanding—basic	**77.6**	77.3	66.3	63.1	56.1
Weighted average shares outstanding—diluted	**78.0**	77.8	67.0	63.7	56.6
Total shares outstanding[2]	**77.7**	77.8	76.7	64.5	56.7
Earnings per share—basic	**$ 2.73**	$ 2.50	$ 2.30	$ 2.03	$ 1.84
Earnings per share—diluted	**$ 2.72**	$ 2.48	$ 2.28	$ 2.01	$ 1.82
Dividends declared per share	**$ 1.48**	$ 1.30	$ 1.15	$ 1.11	$ 1.08
Dividend payout ratio	**54%**	52%	50%	55%	59%
Dividend yield	**3.8%**	3.7%	3.5%	3.8%	4.4%
Book value per share[3]	**$20.72**	$19.27	$18.04	$14.66	$12.52
Price-earnings ratio	**14.3**	13.9	14.5	14.3	13.2
Market value per share[4]	**$38.91**	$34.81	$33.24	$29.10	$24.30
Market value[2]	**$3,023**	$2,708	$2,551	$1,877	$1,378
Balance sheet data[2]					
Total assets	**$6,147**	$6,320	$5,637	$3,972	$3,742
Property, plant and equipment—net	**3,436**	3,333	3,178	2,345	2,194
Working capital	**195**	73	(20)	(306)	(429)
Total debt	**2,161**	2,137	1,957	1,340	1,413
Common shareholders' equity	**1,609**	1,499	1,385	945	710
Cash flow data					
Net cash provided by operating activities	**$ 354**	$ 80	$ 287	$ 122	$ 286
Property, plant and equipment expenditures	**253**	267	264	158	187
Net borrowings and (payments) of short-term debt	**6**	188	(480)	(82)	4
Cash paid for interest	**108**	89	50	60	73
Financial ratios[2]					
Total debt	**57%**	59%	59%	59%	67%
Common shareholders' equity	**43%**	41%	41%	41%	33%
Total	**100%**	100%	100%	100%	100%
Return on average common shareholders' equity	**13.6%**	13.4%	13.1%	15.5%	14.7%

[1] These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – AGL Resources – Results of Operations." [2] As of the last day of the fiscal period. [3] Common shareholders' equity divided by total outstanding common shares as of the last day of the fiscal period. [4] Closing price of common stock on the New York Stock Exchange as of the last trading day of the fiscal period.

MD&A

Item 7 » Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview

We are an energy services holding company whose principal business is the distribution of natural gas in six states—Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. Our six utilities serve more than 2.2 million end-use customers, making us the largest distributor of natural gas in the southeastern and mid-Atlantic regions of the United States based on customer count. We are involved in various related businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for our own utilities as well as for nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability underground natural gas storage assets. We also own and operate a small telecommunications business that constructs and operates conduit and fiber infrastructure within select metropolitan areas. We manage these businesses through four operating segments—distribution operations, retail energy operations, wholesale services and energy investments—and a nonoperating corporate segment. As of December 31, 2006, we employed a total of 2,369 employees across these five segments.

The distribution operations segment is the largest component of our business and is subject to regulation and oversight by agencies in each of the six states we serve. These agencies approve natural gas rates designed to provide us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our fixed and variable costs such as depreciation, interest, maintenance and overhead costs, and to earn a reasonable return for our shareholders. With the exception of Atlanta Gas Light, our largest utility, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions and price levels for natural gas. Our non-Georgia jurisdictions have various regulatory mechanisms to provide us with a reasonable opportunity to recover our costs, but these methods of recovery are not direct offsets to the potential impacts on earnings. Atlanta Gas Light charges rates to its customers primarily as monthly fixed charges. Our retail energy operations segment, which consists of SouthStar, also is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to mitigate potential weather impacts. Our Sequent subsidiary within our wholesale services segment is weather sensitive, with increased earnings opportunities, as well as increased loss potential, during periods of extreme weather conditions, which typically produce greater price volatility. Our energy investments segment's primary business is our natural gas storage, which develops, acquires and operates high-deliverability salt-dome storage assets in the Gulf Coast region of the United States. While this business also can generate additional revenue during times of peak market demand for natural gas storage services, the majority of our storage services are covered under medium- to long-term contracts at a fixed market rate.

2006 Business Highlights

We achieved several significant milestones during 2006 that position us well for future growth and for providing long-term value to our shareholders.

- We completed our rate proceeding in Virginia, which resulted in a five-year rate freeze for customers under the first performance based rate (PBR) plan approved in that state for a natural gas utility. As part of the settlement reached with the parties in the case, we have committed to spend approximately $48 million to $60 million to build a new pipeline that will improve access to natural gas in certain areas we serve in Virginia, particularly during critical peak periods. Also, the Virginia Commission approved a permanent WNA for residential customers as part of the settlement.
- We successfully resolved our rate proceeding in Tennessee, which resulted in a $3 million base rate increase effective January 1, 2007 to offset higher costs and lower natural gas consumption. Additionally, the rate proceeding improved our authorized return and improved our capital structure (55% debt and 45% equity) in a manner that is more consistent with our utilities and other non-affiliated utilities.
- We continued to grow our asset management business at Sequent which enables them to generate greater levels of economic value during periods of market volatility.
- We expanded, through SouthStar, our retail footprint into the Ohio and Florida markets.
- We announced our intention to develop a 12 Bcf natural gas salt-dome storage facility, known as Golden Triangle Storage, in Beaumont, Texas, at a capital cost of approximately $180 million. The project will provide high-deliverability Gulf Coast storage at a key market point, with the first phase scheduled to be in commercial operation in 2010.

2006 Business Results

In 2006, we earned $212 million in net income or $2.72 per diluted share, compared with net income of $193 million, or $2.48 per

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diluted share, in 2005. The 10% increase in net income was the result of a variety of factors:

- Our distribution operations segment's EBIT improved by $11 million or 4% in 2006 as compared to 2005. We continued to benefit from the improved operating metrics of the utilities we acquired in 2004. These results were offset, however, by customer consumption declines due to warmer-than-normal weather throughout the year and high natural gas prices, particularly during the first quarter of 2006.
- Our retail energy operations segment provided stable year-over-year earnings contributions despite the effects of declining customer consumption, warmer weather and a lower of weighted average cost or current market price (LOCOM) adjustment to inventory. This segment's marketing efforts during the year also resulted in a slight increase in customer count.
- Our wholesale services segment captured significant arbitrage opportunities due to price volatility and periods of extreme weather conditions. As a result, this segment's EBIT contribution of $90 million was $41 million higher than in 2005, primarily as a result of additional commercial activity and storage arbitrage opportunities throughout the year, as well as the recognition of hedge gains as forward NYMEX prices declined.
- Our energy investments segment made progress on the evaluation and development of several projects during 2006. While these projects are expected to provide future earnings contributions, the associated business development expenses resulted in a lower year-over-year performance in this segment as well as the disposition in the second half of 2005 of certain non-strategic assets acquired as part of the acquisition of NUI in December 2004.
- Our interest expense for 2006 increased $14 million as compared to 2005. The increase reflects higher carrying costs associated with higher inventory storage balances, as well as higher short-term interest rates, relative to the prior year.

Results of Operations

AGL Resources

Revenues » We generate nearly all our operating revenues through the sale, distribution and storage of natural gas. We include in our consolidated revenues an estimate of revenues from natural gas distributed, but not yet billed, to residential and commercial customers from the latest meter reading date to the end of the reporting period.

Operating Margin and EBIT » We evaluate the performance of our operating segments using the measures of operating margin and EBIT. We believe operating margin is a better indicator than revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of gas can vary significantly and is generally passed directly to our customers. We also consider operating margin to be a better indicator in our retail energy operations, wholesale services and energy investments segments since it is a direct measure of gross profit before overhead costs. We believe EBIT is a useful measurement of our operating segments' performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations.

Our operating margin and EBIT are not measures that are considered to be calculated in accordance with accounting principles generally accepted in the United States of America (GAAP). You should not consider operating margin or EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our operating margin or EBIT measure may not be comparable to similarly titled measures of other companies.

The following table sets forth a reconciliation of our operating margin and EBIT to our operating income and net income, together with other consolidated financial information for the years ended December 31, 2006, 2005 and 2004.

In millions	2006	2005	2004
Operating revenues	$2,621	$2,718	$1,832
Cost of gas	1,482	1,626	995
Operating margin	1,139	1,092	837
Operating expenses			
Operation and maintenance	473	477	377
Depreciation and amortization	138	133	99
Taxes other than income	40	40	29
Total operating expenses	651	650	505
Operating income	488	442	332
Other expenses	(1)	(1)	—
Minority interest	(23)	(22)	(18)
EBIT	464	419	314
Interest expense	123	109	71
Earnings before income taxes	341	310	243
Income taxes	129	117	90
Net income	$ 212	$ 193	$ 153
Earnings per common share:			
Basic	$ 2.73	$ 2.50	$ 2.30
Diluted	$ 2.72	$ 2.48	$ 2.28
Weighted average number of common shares outstanding:			
Basic	77.6	77.3	66.3
Diluted	78.0	77.8	67.0

Segment Information » Operating revenues, operating margin, operating expenses and EBIT information for each of our segments are presented in the following table for the years ended December 31, 2006, 2005 and 2004:

In millions	Operating revenues	Operating margin[1]	Operating expenses	EBIT[1]
2006				
Distribution operations	$1,624	$ 807	$499	$310
Retail energy operations	930	156	68	63
Wholesale services	182	139	49	90
Energy investments	41	36	26	10
Corporate[2]	(156)	1	9	(9)
Consolidated	$2,621	$1,139	$651	$464
2005				
Distribution operations	$1,753	$ 814	$518	$299
Retail energy operations	996	146	61	63
Wholesale services	95	92	42	49
Energy investments	56	40	23	19
Corporate[2]	(182)	—	6	(11)
Consolidated	$2,718	$1,092	$650	$419
2004				
Distribution operations	$1,111	$ 640	$394	$247
Retail energy operations	827	132	62	52
Wholesale services	54	53	29	24
Energy investments	25	13	8	7
Corporate[2]	(185)	(1)	12	(16)
Consolidated	$1,832	$ 837	$505	$314

[1] These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in "Results of Operations – AGL Resources."

[2] Includes the elimination of intercompany revenues and cost of gas.

Discussion of Consolidated Results

2006 compared to 2005 » The increase in EBIT of $45 million or 11% in 2006 was primarily the result of increases at the distribution operations and wholesale services segments. Wholesale services' EBIT improvement of $41 million primarily reflected the recognition of hedge gains during 2006, as forward NYMEX prices declined significantly. In contrast, NYMEX price increases experienced during 2005 had the opposite effect, but to a lesser extent. In the distribution operations segment, EBIT improved by $11 million, and operating margin declined $7 million offset primarily by reduced operating expenses of $19 million. Our retail energy operations segment's EBIT was flat compared to 2005. The energy investments segment's EBIT was down $9 million primarily due to the loss of EBIT contributions as the result of the sale in 2005 of certain assets that were originally acquired with the 2004 acquisition of NUI.

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Our operating margin increased $47 million or 4% from 2005. The following table indicates the significant changes in our operating margin:

In millions	
Operating margin for 2005	$1,092
Net change in the fair value of hedges at wholesale services	60
Increased operating margins at retail energy operations	16
Increased wholesale services commercial activities	5
Wholesale services inventory LOCOM adjustments (net of hedging recoveries)	(18)
Retail energy operations inventory LOCOM adjustments	(6)
Lower operating margins at distribution operations utilities	(7)
Loss of margin from energy investment assets sold in 2005	(9)
Other	6
Operating margin for 2006	**$1,139**

Changes in commodity prices subject a significant portion of our operations to earnings variability. Our nonutility businesses principally use physical and financial arrangements to economically hedge the risks associated with both weather-related seasonal fluctuations and changing commodity prices. In addition, because these economic hedges are generally not designated for hedge accounting treatment, our reported earnings for the wholesale services and retail energy operations segments reflect changes in the fair values of certain derivatives. These values may change significantly from period to period and are reflected as gains or losses within our operating margin or our other comprehensive income (OCI) for those derivative instruments that qualify and are designated as accounting hedges.

Forward NYMEX prices decreased during 2006, especially during the third and fourth quarters. This resulted in the wholesale services segment recognizing $41 million of storage hedge gains in 2006, compared to the recognition of $7 million of storage hedge losses in 2005. In addition, wholesale services recognized $12 million in gains associated with the financial instruments used to hedge its transportation capacity. Consequently, wholesale services experienced a net change of $60 million from its hedging activities for 2006 compared to 2005.

The results of the wholesale services segment also reflect improved commercial activities of approximately $5 million. Sequent was able to capture higher seasonal storage margins in 2006 and additional operating margin opportunities brought on by higher temperatures during the late summer months. This offset the lower operating margins that resulted from milder weather earlier in the year.

As a result of decreasing NYMEX prices, the wholesale services segment evaluated the weighted average cost of its natural gas inventory and recorded LOCOM adjustments totaling $43 million during 2006; however, as inventory was physically withdrawn from storage during the year, $22 million of the 2006 adjustments were recovered and reflected in 2006 operating revenues when the original economic results were realized as the related hedging derivatives were settled.

We experienced increased operating margins at our retail energy operations segment of $10 million driven by improved retail margins of $6 million and slightly higher storage and commercial margins of $4 million. Storage and commercial margins were driven by improved optimization of storage and transportation assets and effective commodity risk management, including net gains on weather derivatives offset by a $6 million adjustment in 2006 to reduce inventory to market for which no LOCOM adjustment was recorded in 2005. Retail operating margins increased due to improved retail price spreads and an increase in the average number of customers offset by lower customer consumption due to weather that was more than 10% warmer than the previous year and lower late payment fees of $1 million due to an increase in the number of customers utilizing payment arrangements.

Operating margin for the distribution operations segment decreased $7 million primarily from warmer weather affecting customer usage and from our exiting the New Jersey and Florida appliance businesses. The margin at Elizabethtown Gas decreased $3 million with 18% warmer weather than in 2005. Virginia Natural Gas' margin decreased $4 million with 17% warmer weather, and the margin at Florida City Gas decreased $2 million with 16% warmer weather. Further, our exiting from the New Jersey and Florida appliance businesses reduced margin by $3 million. This margin reduction was partially offset by increased margin at Atlanta Gas Light of $6 million primarily from gas storage carrying costs from higher average inventory balances and pipeline replacement program revenues from the continuing expenditures under the program.

Our energy investments segment operating margin decreased $4 million due to the loss of contributions from certain assets we acquired with the 2004 acquisition of NUI, but later sold in 2005.

Our operating expenses increased $1 million or 0.2% from the same period in 2005. The following table sets forth the significant components of operating expenses:

In millions	
Operating expenses for 2005	$650
Increased depreciation and amortization	5
Increased payroll, incentive compensation and corporate overhead allocated costs at wholesale services	7
Increased bad debt expenses at retail energy operations and distribution operations	4
Lower expenses resulting from energy investment assets sold in 2005	(8)
Lower expenses at distribution operations related to workforce and facilities restructurings in 2005 and 2006	(15)
Other	8
Operating expenses for 2006	**$651**

The wholesale services segment recorded $7 million of additional costs associated with payroll due to an increased number of employees to support growth and increased incentive compensation, which is generally based on Sequent's operating performance. Bad debt expense for 2006 increased over 2005 primarily in our retail energy operations segment. The retail energy operation's bad debt for 2006 was $13 million, a $3 million increase from the same period in 2005, driven by an increase in the number of accounts receivable balances past due more than 60 days due to higher natural gas bills.

These increases were offset by $15 million in lower costs primarily related to a 2005 restructuring at the distribution operations segment, as a result of a reduction in the workforce and elimination of unnecessary facilities following the 2004 acquisition of NUI. An additional $8 million decrease in operating expenses was related to the operation of assets, primarily in the energy investments segment, that were originally acquired in the 2004 acquisition of NUI and later sold in 2005.

Interest expense for 2006 increased by $14 million or 13% as compared to 2005. As indicated in the following table, higher short-term interest rates and higher debt outstanding combined to increase our interest expense in 2006 relative to the previous year. The increase of $200 million in average debt outstanding for 2006 compared to 2005 was due to additional debt incurred as a result of higher working capital requirements.

In millions	2006	2005
Total interest expense	$ 123	$ 109
Average debt outstanding[1]	2,023	1,823
Average interest rate	6.1%	6.0%

[1] Daily average of all outstanding debt

Based on $733 million of variable-rate debt, which includes $527 million of variable-rate short-term debt, $100 million of variable-rate senior notes and $106 million of variable-rate gas facility revenue bonds outstanding at December 31, 2006, a 100 basis point change in market interest rates from 5% to 6% would result in an increase in annual pretax interest expense of $7 million.

The increase in income tax expense of $12 million or 10% for 2006 compared to 2005 reflected additional income taxes primarily due to higher corporate earnings year over year. We expect our effective tax rate for the year ending December 31, 2007, to be similar to the effective rate for the year ended December 31, 2006.

2005 compared to 2004 » Consolidated EBIT for 2005 increased by $105 million or 33% from the previous year, of which $56 million related to EBIT contributions from the 2004 acquisitions of NUI and Jefferson Island Storage & Hub, LLC (Jefferson Island) and from Pivotal Propane of Virginia, Inc. (Pivotal Propane) which became operational in 2005. The increase further reflected increased contributions of $8 million from Atlanta Gas Light in distribution operations, $11 million from retail energy operations and $3 million from AGL Networks, LLC (AGL Networks) in energy investments. Wholesale services' EBIT increased $25 million primarily due to increased operating margins partially offset by higher operating expenses. Corporate segment results improved by $5 million compared to 2004, primarily due to merger and acquisition-related costs incurred in 2004 but not in 2005.

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Our operating margin in 2005 increased $255 million or 30% from 2004. The following table indicates the significant changes in our operating margin:

In millions	
Operating margin in 2004	$ 837
Increased operating margin at distribution operations from acquired utilities	167
Increased wholesale services commercial activities	53
Increased operating margins at retail energy operations	14
Increased operating margins at Jefferson Island	13
Operating margin from energy investment assets acquired from NUI	8
Increased operating margin at distribution operations, primarily Atlanta Gas Light	7
Increased operating margins at Pivotal Propane and AGL Networks	7
Inventory LOCOM adjustments at wholesale services	(2)
Net change in the fair value of hedges at wholesale services	(12)
Operating margin in 2005	$1,092

The increase primarily reflects the NUI and Jefferson Island acquisitions and completion of the Pivotal Propane facility in Virginia, as well as improved margins at SouthStar, Sequent and AGL Networks. Excluding the addition of the NUI utilities, distribution operations' margins improved by $7 million mainly as a result of higher pipeline replacement revenues and additional carrying costs charged to Marketers for gas storage. Retail energy operations' margins increased $14 million, due primarily to higher commodity margins. Wholesale services' operating margin increased $39 million year over year, primarily due to significant market volatility following the hurricane activity during the third quarter and the continuing volatile market conditions during the fourth quarter of 2005. Energy investments' margins were up $27 million, primarily as a result of the acquisition of Jefferson Island that contributed $13 million, contributions from NUI's nonutility businesses of $8 million, contribution from Pivotal Propane of $3 million and improved operating margin at AGL Networks of $4 million.

Our operating expenses increased $145 million or 29% from 2004. The following table sets forth the significant changes in our operating expenses:

In millions	
Operating expenses in 2004	$505
Operating expenses at distribution operations from NUI utilities acquired December 2004	125
Increased operating expenses at wholesale services, primarily payroll, incentive compensation and depreciation	13
Operating expenses at energy investments from NUI-acquired assets	8
Operating expenses at Jefferson Island	3
Operating expenses at energy investments from Pivotal Propane	3
Other	(7)
Operating expenses in 2005	$650

The increase was primarily a result of $124 million in higher expenses at distribution operations due to the addition of NUI. In addition, operating expenses at energy investments increased $15 million primarily due to the addition of Jefferson Island, the NUI nonutility assets and Pivotal Propane. Operating expenses at wholesale services increased $13 million due to increased payroll and employee incentive compensation costs resulting from its operational and financial growth and depreciation on a trading and risk management system placed in service during 2004. The increased operating expenses were offset by lower corporate operating expenses primarily due to prior-year costs incurred with merger and acquisition activities.

Interest expense for 2005 increased by $38 million or 54% as compared to 2004. As indicated in the table below, higher short-term interest rates and higher average debt outstanding combined to increase our interest expense in 2005 relative to the previous year. The increase of $549 million in average debt outstanding for 2005 was due to additional debt incurred as a result of the acquisitions of NUI and Jefferson Island and higher working capital requirements as a result of higher natural gas prices.

In millions	2005	2004
Total interest expense	$ 109	$ 71
Average debt outstanding[1]	1,823	1.274
Average interest rate	6.0%	5.6%

[1] Daily average of all outstanding debt

The increase in income tax expense of $27 million or 30% for 2005 compared to 2004 reflected additional income taxes of $25 million due to higher corporate earnings year over year and $2 million due to a slightly higher effective tax rate of 38% for 2005 as compared to 37% in 2004.

Distribution Operations

Distribution operations includes our six natural gas local distribution utility companies that construct, manage and maintain intrastate natural gas pipelines and distribution facilities and serve more than 2.2 million end-use customers.

Atlanta Gas Light » This natural gas local distribution utility operates distribution systems and related facilities throughout Georgia serving approximately 1.5 million end-use customers. Atlanta Gas Light customer counts are approximately 94% residential and 6% commercial or industrial. Atlanta Gas Light is regulated by the Georgia Commission and its rates are frozen until 2010.

Atlanta Gas Light's natural gas market was deregulated in 1997 with Georgia's Natural Gas Competition and Deregulation Act (Deregulation Act). Prior to this act, Atlanta Gas Light was the supplier and seller of natural gas to its customers. Today, Marketers—that is, marketers who are certificated by the Georgia Commission to sell retail natural gas in Georgia on terms approved by the Georgia Commission—sell natural gas to end-use customers in Georgia and handle customer billing functions. The Marketers file their rates monthly with the Georgia Commission. Atlanta Gas Light's role includes

- distributing natural gas for Marketers
- constructing, operating and maintaining the gas system infrastructure, including responding to customer service calls and leaks
- reading meters and maintaining underlying customer premise information for Marketers

Elizabethtown Gas » This natural gas local distribution utility operates distribution systems and related facilities serving approximately 269,000 customers in central and northwestern New Jersey. Most Elizabethtown Gas customers are located in densely populated central New Jersey, where increases in the number of customers primarily result from conversions to gas heating from alternative forms of heating. In the northwestern region of the state, customer additions are driven primarily by new construction. Elizabethtown Gas customer counts are approximately 92% residential and 8% commercial or industrial. Elizabethtown Gas is regulated by the New Jersey Commission and its rates are frozen until 2010.

Virginia Natural Gas » This natural gas local distribution utility operates distribution systems and related facilities serving approximately 264,000 customers in southeastern Virginia. Virginia Natural Gas customer counts are approximately 92% residential and 8% commercial or industrial. Virginia Natural Gas is regulated by the Virginia Commission and its rates are frozen until 2011 subject to the terms of its PBR plan.

Florida City Gas » This natural gas local distribution utility operates distribution systems and related facilities serving approximately 104,000 customers in central and southern Florida. Florida City Gas customers purchase gas primarily for heating water, drying clothes and cooking. Some customers, mainly in central Florida, also purchase gas to provide space heating during the winter season. Florida City Gas customer counts are approximately 94% residential and 6% commercial or industrial. Florida City Gas is regulated by the Florida Commission.

Chattanooga Gas » This natural gas local distribution utility operates distribution systems and related facilities serving approximately 61,000 customers in the Chattanooga and Cleveland areas of southeastern Tennessee. Chattanooga Gas customer counts are approximately 86% residential and 14% commercial or industrial. Chattanooga Gas is regulated by the Tennessee Commission.

Elkton Gas » This natural gas local distribution utility operates distribution systems and related facilities serving approximately 6,000 customers in Cecil County, Maryland. Elkton Gas customer counts are approximately 92% residential and 8% commercial or industrial. Elkton Gas is regulated by the Maryland Commission.

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The following table provides operational information for our five largest utilities. The daily capacity represents total system capability, and the storage capacity includes on-system LNG and propane volumes.

	Atlanta Gas Light	Elizabethtown Gas	Virginia Natural Gas	Florida City Gas	Chattanooga Gas
Operations					
2006 avg. customers (in thousands)	1,546	269	264	104	61
2005 avg. customers (in thousands)	1,545	266	261	103	61
2004 avg. customers (in thousands)[6]	1,533	263	256	103	60
Storage capacity[1]	48.4	13.0	9.6	—	3.6
Throughput—2006[1]	211	46	33	9	15
Throughput—2005[1]	232	59	36	10	16
Throughput—2004[1,6]	233	65	34	9	16
Peak storage capacity[1]	7.8	0.8	1.6	—	1.2
Miles of main[7]	30,284	3,030	5,235	3,207	1,521
Heating degree days—2006[2]	2,466	4,110	2,869	696	2,898
2006 % warmer than 2005	(10)%	(18)%	(17)%	(16)%	(7)%
Heating degree days—2005[2]	2,726	5,017	3,465	829	3,115
2005 % colder than 2004	5%	2%	8%	3%	3%
Heating degree days—2004[2,6]	2,589	4,918	3,214	802	3,010
Rates					
Last decision on change in rates	Jun. 2005	Nov. 2002	Oct. 1996	Feb. 2004	Dec. 2006
Authorized return on rate base[5]	8.53%	7.95%	9.24%	7.36%	7.43%
Estimated 2006 return on rate base[3]	8.45%	7.83%	7.65%	7.41%	7.00%
Authorized return on equity	10.9%	10.0%	10.9%	11.25%	10.2%
Estimated 2006 return on equity[3]	10.73%	9.40%	8.49%	10.67%	9.01%
Authorized rate base % of equity[5]	47.9%	53.0%	52.4%	36.8%	35.5%
Rate base included in 2006 return on equity (in millions)[4]	$1,238	$417	$351	$120	$102

[1] In Bcf.

[2] We measure effects of weather on our businesses using "degree days." The measure of degree days for a given day is the mean daily temperature (average of the daily high and low temperature) and a base-line temperature of 65 degrees Fahrenheit. Heating degree days result when the mean daily temperature is less than the 65 degree baseline. Generally, increased heating degree days result in greater demand for gas on our distribution systems.

[3] Estimate based on principles consistent with utility ratemaking in each jurisdiction. Returns are not necessarily consistent with GAAP returns.

[4] Estimated based on 13-month average.

[5] The authorized return on rate base, return on equity and percentage of equity reflected above were those authorized as of December 31, 2006. Effective January 1, 2007, Chattanooga Gas' authorized return on rate base, return on equity and percentage of equity are 7.89%, 10.2% and 44.[illegible]%, respectively, due to the results of its base rate case settled in December 2006.

[6] Includes amounts for the full year of 2004; however, we acquired these utilities in December 2004. The December 2004 end-use customers for Elizabethtown Gas were 266 and 103 for Florida City Gas. December 2004 distribution for Elizabethtown Gas was 9.2 and 0.3 for Florida City Gas, and December 2004 heating degree days for Elizabethtown Gas were 872 and 239 for Florida City Gas.

[7] Includes distribution and transmission mains only.

Regulatory Environment » Each utility operates subject to regulations provided by the state regulatory agency in its service territories with respect to rates charged to our customers and various service and safety matters. Rates charged to our customers vary according to customer class (residential, commercial or industrial) and rate jurisdiction. Rates are set at levels that allow recovery of all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return on common equity. Rate base generally consists of the original cost of utility plant in service, working capital, inventories and certain other assets; less accumulated depreciation on utility plant in service, net deferred income tax liabilities and certain other deductions. Our utilities are authorized to use a purchased gas adjustment (PGA) mechanism that allows them to automatically adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure the utilities recover 100% of the costs incurred in purchasing gas for their customers. We continuously monitor the performance of our utilities to determine whether rates need to be further adjusted through a rate case filing.

Straight-Fixed-Variable Rates » Atlanta Gas Light recognizes revenue under a straight-fixed-variable rate design whereby Atlanta Gas Light charges rates to its customers based primarily on monthly fixed charges, however the Marketers bill these charges directly to their customers. This mechanism minimizes the seasonality of revenues since the monthly fixed charge is not volumetric and the monthly charge is not set to be directly weather dependent. Weather indirectly influences the number of customers that have active accounts during the heating season, and this has a seasonal impact on Atlanta Gas Light's revenues since generally more customers are connected in periods of colder weather than in periods of warmer weather.

Weather Normalization » The tariffs of Elizabethtown Gas, Virginia Natural Gas, and Chattanooga Gas contain WNA provisions that are designed to help stabilize operating margin results by increasing base rate amounts charged to customers when weather is warmer than normal and decreasing amounts charged when weather is colder than normal. The WNA is most effective in a reasonable temperature range relative to normal weather using historical averages. For Elizabethtown Gas, the weather normalization provision was renewed in October 2004 and is based on a 20-year average of weather conditions.

Virginia Natural Gas received from the Virginia Commission approval of a weather normalization program in September 2002 as a two-year experiment involving the use of special rates. In September 2004, Virginia Natural Gas received approval from the Virginia Commission to extend the WNA program for an additional two years with certain modifications to the existing program. The modifications included removal of the commercial class of customers from the WNA program and the use of a rolling 30-year average to calculate the weather factor that is updated annually. The residential WNA program was made permanent by Virginia Commission order in September 2006.

Chattanooga Gas' base rates include a weather normalization provision that allows for revenue to be recognized based on a factor derived from average temperatures over a 30-year period, which offsets the impact of unusually cold or warm weather on its operating income.

Rate Settlement Agreements » On July 24, 2006, the Virginia Commission issued an order approving Virginia Natural Gas' PBR plan with modifications. Under the PBR rate plan, Virginia Natural Gas' rates were frozen as an incentive for it to promote cost containment, productivity and rate stability without traditional rate proceedings that set rates based on investment, return and cost of service. These modifications include a requirement to construct and report on the progress of a pipeline connecting Virginia Natural Gas' northern and southern systems and reporting requirements to monitor compliance with the terms of the PBR plan. Virginia Natural Gas accepted the terms of the PBR plan as modified by the Virginia Commission in August 2006. The modified PBR plan was effective August 1, 2006 with base rates frozen at current levels for five years. The estimated cost to construct the pipeline is between $48 million and $60 million, and the pipeline is expected to be completed in 2009.

On June 30, 2006, we filed a general rate case with the Tennessee Commission seeking approximately $6 million in increased annual base rates to cover the rising cost of service at Chattanooga Gas. Our rate case included a proposal for comprehensive rate design, including an energy conservation program (ECP) and a conservation and usage adjustment (CUA). The ECP would provide incentives for customers to reduce their natural gas consumption by offering rebates for more energy-efficient appliances and to help customers better manage their energy costs. The CUA is designed to mitigate the financial impact on Chattanooga Gas of expected increased energy conservation by customers through rate adjustments.

The Tennessee Commission divided the case into two phases: one phase to examine the revenue requirements and traditional rate design issues and a second phase to review the CUA and ECP. Approximately $5 million of our base rate request was related to the revenue requirement. In December 2006, the Tennessee Commission approved a settlement agreement between Chattanooga Gas, the Consumer Advocate and Protection Division of the Attorney General's Office (Consumer Advocate) and the Chattanooga Manufacturers Association settling the revenue requirements and traditional rate design issues of the case. The settlement agreement was effective January 1, 2007, and provides for a base rate increase of approximately $3 million of which $2 million will be an increase in operating margin and the remaining will be a $1 million shift from WNA to base rates and have no overall impact on operating margin.

The settlement agreement establishes an authorized return on equity of 10.2% for Chattanooga Gas, resulting in an overall authorized rate of return of 7.89%. Prior to the settlement agreement, Chattanooga Gas' authorized return on equity was 10.2% and its overall authorized rate of return was set at 7.43%. The second phase of the case is scheduled to begin in February 2007 with a final ruling expected by September 30, 2007.

Customer Demand » Our distribution operations businesses face competition based on customer preferences for natural gas compared to other energy products and the comparative prices of those products. Our principal competition relates to electric utilities and oil and propane providers serving the residential and commercial markets throughout our service areas primarily through the potential displacement or replacement of natural gas appliances

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with electric appliances. The primary competitive factors are the prices for competing sources of energy and the desirability of natural gas heating versus alternative heating sources.

Competition for space heating and general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally continue to use the chosen energy source for the life of the equipment. Customer demand for natural gas could be affected by numerous factors, including:

- changes in the availability or price of natural gas and other forms of energy
- general economic conditions
- energy conservation
- legislation and regulations
- the capability to convert from natural gas to alternative fuels
- weather
- new housing starts

In some of our service areas, net growth continues to be slowed due to the number of customers who leave our systems because of higher natural gas prices and competition from alternative fuel sources, including incentives offered by the local electric utilities to switch to electric heat alternatives.

We expect customer growth to improve in the future through our efforts to obtain new customers and retain existing customers. These efforts include working to add residential customers, multifamily complexes and high-value commercial customers that use natural gas for purposes other than space heating. In addition, we partner with numerous entities to market the benefits of gas appliances and to identify potential retention options early in the process for those customers who might consider converting to alternative fuels.

Collective Bargaining Agreements » In 2006, a collective bargaining agreement representing approximately 300 Atlanta Gas Light employees by Teamsters Local 528 was not renewed. As a result, these employees are no longer represented by a bargaining unit and now fall under our standard human resources pay and benefit plans and policies. In January 2007, a majority of Chattanooga Gas' bargaining unit employees submitted a petition to Chattanooga Gas requesting the decertification of the Utility Workers Union of America, Local 461, as their bargaining representative. Based on that majority showing, Chattanooga Gas filed a petition with the National Labor Relations Board requesting that the Board conduct a decertification election. The decertification election is currently scheduled to take place on February 16, 2007. The following table provides information about the collective bargaining agreements to which our natural gas local distribution utilities are parties:

	Affiliated subsidiary	Approximate # of employees	Date of contract expiration
Communications Workers of America (Local No. 1023)	Elizabethtown Gas	8	April 2007
Utility Workers Union of America (Local No. 461)	Chattanooga Gas	21	April 2007
International Union of Operating Engineers (Local No. 474)	Atlanta Gas Light	26	August 2007
Teamsters (Local Nos. 769 and 385)	Florida City Gas	50	March 2008
Utility Workers Union of America (Local No. 424)	Elizabethtown Gas	160	November 2009
International Brotherhood of Electrical Workers (Local No. 50)	Virginia Natural Gas	141	May 2010
	Total	406	

Results of Operations » The following table presents results of operations for distribution operations for the years ended December 31, 2006, 2005 and 2004.

In millions	2006	2005	2004
Operating revenues	$1,624	$1,753	$1,111
Cost of gas	817	939	471
Operating margin[1]	807	814	640
Operating expenses	499	518	394
Operating income	308	296	246
Other income	2	3	1
EBIT[1]	$ 310	$ 299	$ 247
Metrics[2]			
Average end-use customers (in thousands)	2,250	2,242	1,880
Operation and maintenance expenses per customer	$ 156	$ 166	$ 152
EBIT per customer	$ 138	$ 133	$ 131

[1] These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in "Results of Operations – AGL Resources."

[2] 2004 metrics include only December for Florida City Gas, Elizabethtown Gas and Elkton Gas.

2006 compared to 2005 » EBIT increased $11 million or 4% in 2006 reflecting a decrease in operating expenses of $19 million, partially offset by decreased operating margin of $7 million.

The operating margin decrease of $7 million or 1% in 2006 was primarily the result of lower usage resulting from customer conservation and warmer weather. Operating margins decreased $4 million at Virginia Natural Gas, $3 million at Elizabethtown Gas and $2 million at Florida City Gas. Also contributing to the decrease was a $3 million decrease due to our exit from the New Jersey and Florida appliance business operations in 2005. These decreases were offset by a net increase in Atlanta Gas Light's operating margin of $6 million consisting of $5 million in gas storage carrying costs and $2 million in pipeline replacement program (PRP) revenues, offset primarily by $2 million as a result of the effect of the Georgia Commission's June 2005 Rate Order.

Operating expenses decreased $19 million or 4% in 2006 compared to the same period in 2005, primarily due to lower compensation and facilities expense of $10 million, resulting from a workforce and facilities restructuring in 2005, $5 million of reduced outside services and $3 million in lower costs due to our exiting the appliance businesses acquired with our purchase of NUI. These decreases were offset by a $1 million increase in bad debt expense primarily at Elizabethtown Gas due to higher gas prices in 2006. Operating expenses also reflect a $2 million net gain compared to 2005 primarily due to the sale of properties in Georgia in 2006.

2005 compared to 2004 » EBIT increased $52 million or 21% reflecting an increase in operating margin of $174 million, partially offset by increased operating expenses of $124 million. The businesses acquired from NUI on November 30, 2004 contributed approximately $50 million of EBIT in 2005 compared to $7 million in 2004. This was due to the inclusion of the full-year NUI results in 2005 as compared to the inclusion of one month in 2004.

The $174 million or 27% increase in operating margin was primarily due to the addition of NUI's operations, which contributed $167 million. The remainder was primarily due to $8 million of higher operating margin at Atlanta Gas Light. The increase at Atlanta Gas Light resulted primarily from higher PRP revenues of $6 million and higher revenue of $3 million from additional carrying charges to Marketers for gas stored, primarily due to higher gas prices. Atlanta Gas Light also had approximately $3 million of increased operating margin from net customer growth, which offset a $3 million decrease in operating revenues that resulted from the June 2005 Settlement Agreement with the Georgia Commission. Operating margin at Virginia Natural Gas and Chattanooga Gas remained relatively flat compared to 2004.

The $124 million or 31% increase in operating expenses primarily reflected the addition of NUI's operations which increased operating expenses by $125 million.

Retail Energy Operations

Our retail energy operations segment consists of SouthStar, a joint venture owned 70% by our subsidiary, Georgia Natural Gas Company, and 30% by Piedmont Natural Gas (Piedmont). SouthStar markets natural gas and related services to retail customers on an unregulated basis, principally in Georgia as well as to commercial and industrial customers in Tennessee, North Carolina, South Carolina and Alabama. During 2006, SouthStar entered into agreements with customers in Ohio and Florida to supply natural gas starting in the fourth quarter of 2006.

The SouthStar executive committee, which acts as the governing board, is comprised of six members, three representatives from AGL Resources and three from Piedmont. Under the joint venture agreement, all significant management decisions require the unanimous approval of the SouthStar executive committee; accordingly, our 70% financial interest is considered to be noncontrolling. Although our ownership interest in the SouthStar partnership is 70%, SouthStar's earnings are allocated 75% to us and 25% to Piedmont, under an amended and restated joint venture agreement executed in March 2004. Earnings related to customers in Ohio and Florida are allocated 70% to us and 30% to Piedmont. We record the earnings allocated to Piedmont as a

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minority interest in our consolidated statements of income, and we record Piedmont's portion of SouthStar's capital as a minority interest in our consolidated balance sheets.

Competition » SouthStar competes with other energy marketers, including Marketers in Georgia, to provide natural gas and related services to customers in Georgia and the Southeast. Based on its market share, SouthStar is the largest Marketer of natural gas in Georgia, with average customers over the last three years in excess of 530,000.

In addition, similar to distribution operations, SouthStar faces competition based on customer preferences for natural gas compared to other energy products and the comparative prices of those products. SouthStar's principal competition for other non-natural gas energy products relates to electric utilities and the potential displacement or replacement of natural gas appliances with electric appliances. This competition with other energy products has been exacerbated by price volatility in the wholesale natural gas commodity market and related significant increases in the cost of natural gas billed to SouthStar's customers, especially during the fourth quarter of 2005 and the first and second quarters of 2006.

Operating Margin » SouthStar generates operating margin primarily in three ways. The first is through the sale of natural gas to retail customers in the residential, commercial and industrial sectors, primarily in Georgia where SouthStar captures a spread between wholesale and retail natural gas prices. The second way is through the collection of monthly service fees and customer late payment fees.

The combination of these two retail price components is evaluated by SouthStar to ensure such pricing is structured to cover related retail customer costs, such as bad debt expense, customer service and billing, and lost and unaccounted-for gas, and to provide a reasonable profit, as well as being competitive to attract new customers and maintain market share. SouthStar's operating margins are impacted by seasonal weather, natural gas prices, customer growth and SouthStar's related market share in Georgia, which has historically been approximately 35%. SouthStar employs strategies to attract and retain a higher credit-quality customer base. These strategies result not only in higher operating margin, as these customers tend to utilize higher volumes of natural gas, but also help to mitigate bad debt expense due to the higher credit-quality of customers.

The third way SouthStar generates margin is through its commercial operations of optimizing storage and transportation assets and effectively managing commodity risk, which enables SouthStar to maintain competitive retail prices and operating margins. SouthStar is allocated storage and pipeline capacity that is used to supply gas to its customers in Georgia. Through hedging transactions, SouthStar manages exposures arising from changing commodity prices using natural gas storage transactions to capture margin from natural gas pricing differences that occur over time. SouthStar's risk management policies allow the use of derivative instruments for hedging and risk management purposes but prohibit the use of derivative instruments for speculative purposes.

SouthStar accounts for its natural gas inventories at the lower of weighted average cost or current market price. SouthStar evaluates the weighted average cost of its natural gas inventories against market prices and determines whether any declines in market prices below the weighted average cost are other than temporary. For declines considered to be other than temporary, SouthStar records adjustments to cost of gas in our consolidated statement of income to reduce the weighted average cost of the natural gas inventory to the current market price. As of December 31, 2006, SouthStar recorded a LOCOM adjustment of $6 million. SouthStar did not record a LOCOM adjustment in 2005 or 2004.

We have designated a portion of SouthStar's derivative transactions as cash flow hedges under Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period as the underlying hedged item occurs and is recorded in earnings. We record any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not offset and are greater than the losses or gains on the hedged item, in cost of gas in our consolidated statement of income in the period in which the ineffectiveness occurs. SouthStar currently has minimal hedge ineffectiveness. We have not designated the remainder of SouthStar's derivative instruments as hedges under SFAS 133 and, accordingly, we record changes in their fair value in earnings in the period of change.

SouthStar also enters into weather derivative instruments in order to preserve margins in the event of warmer-than-normal weather in the winter months. These contracts are accounted for using the intrinsic value method under Emerging Issues Task Force (EITF) Issue No. 99-02, "Accounting for Weather Derivatives." The weather derivative contracts contain settlement provisions based on cumulative heating degree days for the covered periods. In September 2006, SouthStar entered into weather derivatives (swaps and options) for the current winter heating season. During 2006, SouthStar recorded net gains on these weather derivatives of approximately $5 million. These gains were largely offset by a corresponding loss of operating margin due to the warm weather the hedge was designed to protect against.

Impact of Volatility in Natural Gas Prices » SouthStar's operating margin and EBIT from the sales of natural gas to retail customers were affected by lower average usage in part due to conservation and higher bad debt as a result of higher and more volatile natural gas prices during the 2005-2006 heating season. SouthStar was also affected when natural gas prices further declined at the end of 2006 resulting in a LOCOM adjustment to inventory.

SouthStar's operating margin and EBIT associated with the optimization of storage and transportation assets and commodity risk management during 2006 were affected by the decline in wholesale natural gas prices. In 2005, natural gas prices were significantly higher in part due to gas supply disruptions brought on by hurricanes Katrina and Rita. For derivatives not designated as hedges under SFAS 133, SouthStar generally records fair value losses as natural gas prices decrease and fair value gains as natural gas prices increase.

SouthStar's bad debt expense was $13 million for 2006, a $3 million increase from 2005. The increase in bad debt was impacted by an increase in the amount of accounts receivable balances past due more than 60 days and the expectation that a majority of these past due accounts will not be collected. In addition, $1 million of aged deposits were applied to SouthStar's bad debt on a one-time basis in 2005. SouthStar entered into payment arrangements with these customers in an effort to help customers pay their higher natural gas bills during the 2005–2006 heating season. We expect that SouthStar's collection efforts will continue to help mitigate the overall impact of bad debt expense as a percentage of operating revenues, which were 1.4% for the year ended December 31, 2006 compared to approximately 1.1% (excluding the one-time application of aged deposits) for the same period in 2005. We further believe that SouthStar's higher credit-quality customer base mitigates our exposure to higher bad debt expenses.

SouthStar also has experienced lower average usage per customer during 2006, compared to the same period in 2005 due to a number of factors including warmer weather and the effects of customer conservation. Though these two factors have contributed to a $16 million unfavorable impact on operating margin, net of gains on weather derivatives, relative to wholesale prices and normalized temperatures, SouthStar achieved a net increase in operating margin of $10 million for 2006 compared to 2005.

Ohio Retail Market » In August 2006, SouthStar was awarded the right to supply approximately a total of 10 Bcf of natural gas to customers of Dominion East Ohio (Dominion Ohio) through August 2008 (approximately 5 Bcf/year). As part of this agreement, SouthStar will manage supply, transportation and storage of natural gas on behalf of Dominion Ohio. While we do not expect the Dominion Ohio agreement to materially impact our results of operations, SouthStar's entrance into the Ohio market is part of its continued growth strategy.

Results of Operations » The following table presents results of operations for retail energy operations for the years ended December 31, 2006. 2005, and 2004.

In millions	2006	2005	2004
Operating revenues	$930	$996	$827
Cost of gas	774	850	695
Operating margin[1]	156	146	132
Operating expenses	68	61	62
Operating income	88	85	70
Other expense	(2)	—	—
Minority interest	(23)	(22)	(18)
EBIT[1]	$ 63	$ 63	$ 52
Metrics – Georgia Market			
Average customers (in thousands)	533	531	533
Market share in Georgia	35%	35%	36%
Natural gas volumes (Bcf)	38	44	45

[1] These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in "Results of Operations – AGL Resources."

2006 compared to 2005 » EBIT for 2006 was relatively flat as compared to 2005, driven by a $10 million increase in operating margin which was offset by a $7 million increase in operating expenses. a $2 million increase in other expense and a $1 million increase in minority interest due to the slightly higher operating income.

Operating margin increased by $10 million or 7% driven by improved retail operating margins of $6 million and higher storage margin gains of $4 million. Retail operating margins increased due to improved retail spreads and an increase of approximately 2,000 average customers in 2006 compared to 2005, offset by lower customer consumption due to weather that was approximately 10% warmer than 2005 and conservation. Late payment fees were $1 million lower in 2006 as compared to 2005 due to more customers being on payment arrangements in 2006. Additionally, retail operating margins decreased compared to 2005 due to higher interruptible margins in 2005 driven by peaking sales during

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curtailments. Storage margins were driven by improved optimization of storage and transportation assets and effective commodity risk management including net gains on weather derivatives. Storage operating margins were impacted by an adjustment in 2006 of $6 million to reduce inventory to market for which no LOCOM adjustment was recorded in 2005.

Operating expenses increased $7 million or 11% primarily due to higher bad debt expense of $3 million, increased depreciation of $1 million due to the implementation of system enhancements, higher outside service costs of $1 million principally driven by the current-year implementation of a new energy trading and risk management (ETRM) system and $1 million from increases in other general corporate overhead costs.

The retail energy operations segment made a $2 million charitable contribution in 2006. Minority interest increased $1 million as a result of increased operating income in 2006 compared to 2005.

2005 compared to 2004 » The $11 million or 21% increase in EBIT for 2005 was driven by a $14 million increase in operating margin and a $1 million decrease in total operating expenses, offset by a $4 million increase in minority interest due to higher earnings.

The $14 million or 11% increase in operating margin was primarily the result of higher commodity margins and positive margin captured with SouthStar's storage assets, offset by lower customer usage and lower late payment fees relative to 2004.

There was a slight decrease in operating expenses in 2005 compared to 2004. The decrease was primarily due to $1 million in lower bad debt expense resulting from ongoing collection process improvements. Minority interest increased $4 million or 22% as a direct result of increased operating income in 2005 compared to 2004.

Wholesale Services

Wholesale services consists of Sequent, our subsidiary involved in asset management, transportation, storage, producer and peaking services and wholesale marketing. Our asset management business focuses on capturing economic value from idle or underutilized natural gas assets, which are typically amassed by companies via investments in or contractual rights to natural gas transportation and storage assets. Margin is typically created in this business by participating in transactions that balance the needs of varying markets and time horizons.

Sequent provides customers with natural gas from the major producing regions and market hubs primarily in the eastern and mid-continental United States. Sequent purchases transportation and storage capacity to meet its delivery requirements and customer obligations in the marketplace. Sequent's customers benefit from its logistics expertise and ability to deliver natural gas at prices that are advantageous relative to other alternatives available to its customers. In 2006, Sequent entered into an agreement which should facilitate the expansion of its operations into the western United States and Canada and plans to pursue additional opportunities in these regions during 2007. Sequent continues to work on projects and transactions to extend its operating territory and is entering into agreements of longer duration, as well as evaluating opportunities to expand its business focus and models.

Seasonality » Fixed cost commitments are generally incurred evenly over the year, while margins generated through the use of the assets are generally greatest in the winter heating season and occasionally in the summer due to peak usage by power generators in meeting air-conditioning load. This increases the seasonality of Sequent's business, generally resulting in higher margins in the first and fourth quarters.

Competition » Sequent competes for asset management business with other energy wholesalers, often through a competitive bidding process. There has been significant consolidation of energy wholesale operations, particularly among major gas producers. Financial institutions have also entered the marketplace. As a result, energy wholesalers have become increasingly willing to place bids for asset management transactions that are priced to capture market share. We expect this trend to continue in the near term, which could result in downward pressure on the volume of transactions and the related margins available in this portion of Sequent's business.

Asset Management Transactions » Our asset management customers include our own utilities, nonaffiliated utilities, municipal utilities and large industrial customers. These customers must independently contract for transportation and storage capacity to meet their demands, and they typically contract for this capacity on a 365-day basis even though they may only need a portion of the capacity to meet their peak demands. Sequent enters into agreements with these customers, either through contract assignment or agency arrangement, whereby Sequent uses the customers' rights to transportation and storage capacity during periods when customers do not need it. Sequent captures margin by optimizing the purchase, transportation, storage and sale of natural gas, and Sequent typically either shares profits with customers or pays them a fee for using their assets.

The following table provides additional information on Sequent's asset management agreements with its affiliated utilities.

In millions	Expiration date	Timing of payment	Type of fee structure	% Shared or annual fee	Profit sharing/fees payments 2006	2005	2004
Elkton Gas	Mar 2008	Monthly	Fixed-fee	(A)	$ —	$ —	$ —
Chattanooga Gas	Mar 2008	Annually	Profit-sharing	50%	4	2	1
Atlanta Gas Light	Mar 2008	Semi-annually	Profit-sharing	60%	6	4	4
Elizabethtown Gas	Mar 2008	Monthly	Fixed-fee	$4	4	—	—
Florida City Gas	Mar 2008	Annually	Profit-sharing	50%	—	—	—
Virginia Natural Gas	Mar 2009	Annually	Profit-sharing	(B)	2	5	3
Total					$16	$11	$ 8

(A) Annual fixed fee is less than $1 million

(B) Profit sharing is based on a tiered sharing structure

In January 2006, the Georgia Commission extended the asset management agreement between Sequent and Atlanta Gas Light for two additional years. In addition, Sequent's asset management agreements with Chattanooga Gas and Elkton Gas were extended for an additional year through March 2008.

Transportation Transactions » Sequent contracts for natural gas transportation capacity and participates in transactions that manage the natural gas commodity and transportation costs to result in the lowest cost to serve its various markets. Sequent seeks to optimize this process on a daily basis as market conditions change by evaluating all the natural gas supplies, transportation alternatives and markets to which it has access and identifying the least-cost alternatives to serve the various markets. This enables Sequent to capture geographic pricing differences across these various markets as delivered gas prices change.

As Sequent executes transactions to secure transportation capacity, it often enters into forward financial contracts to hedge its positions. The hedging instruments are derivatives, and Sequent reflects changes in the derivatives' fair value in its reported operating results. During 2006, Sequent reported gains of $12 million associated with transportation capacity hedges. The majority of this amount will be reversed during 2007 as the positions are settled. Sequent did not report any significant gains or losses on these types of hedges during 2005 or 2004.

Producer Services » Sequent's producer services business primarily focuses on aggregating natural gas supply from various small and medium-sized producers located throughout the natural gas production areas of the United States, principally in the Gulf Coast region. Sequent provides producers with certain logistical and risk management services that offer producers attractive options to move their supply into the pipeline grid. Aggregating volumes of natural gas from these producers allows Sequent to provide markets to producers who seek a reliable outlet for their natural gas production.

Peaking Services » Sequent generates operating margin through, among other things, the sale of peaking services, which includes receiving a fee from affiliated and nonaffiliated customers that guarantees those customers will receive gas under peak conditions. Sequent incurs costs to support its obligations under these agreements, which are reduced in whole or in part as the matching obligations expire. Sequent will continue to seek new peaking transactions as well as work toward extending those that are set to expire.

Credit Rating » Sequent has certain trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, Sequent would need to post collateral to continue transacting with some of its counterparties. Posting collateral would have a negative effect on our liquidity. If such collateral were not posted, Sequent's ability to continue transacting with these counterparties would be impaired. If at December 31, 2006 our credit ratings had been downgraded to non-investment grade, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $10 million.

Energy Marketing and Risk Management Activities » We account for derivative transactions in connection with Sequent's energy marketing activities on a fair value basis in accordance with SFAS 133. We record derivative energy commodity contracts (including both physical transactions and financial instruments) at fair value, with unrealized gains or losses from changes in fair value reflected in our earnings in the period of change.

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Sequent's energy-trading contracts are recorded on an accrual basis as required under the EITF Issue No. 02-03, "Issues Involved in Accounting for Contracts under EITF Issue No. 98-10, 'Accounting for Contracts Involved in Energy Trading and Risk Management Activities'" (EITF 02-03) rescission of EITF 98-10, unless they are derivatives that must be recorded at fair value under SFAS 133.

As shown in the table below, Sequent recorded a net unrealized gain related to changes in the fair value of derivative instruments utilized in its energy marketing and risk management activities of $132 million during 2006, $30 million of unrealized losses during 2005 and unrealized gains of $22 million during 2004. The tables below illustrate the change in the net fair value of the derivative instruments and energy-trading contracts during 2006, 2005 and 2004 and provide details of the net fair value of contracts outstanding as of December 31, 2006.

In millions	2006	2005	2004
Net fair value of contracts outstanding at beginning of period	**$ (13)**	$ 17	$ (5)
Contracts realized or otherwise settled during period	**17**	(47)	11
Change in net fair value of contract gains	**115**	17	11
Net fair value of new contracts entered into during period	**—**	—	—
Net fair value of contracts outstanding at end of period	**119**	(13)	17
Less net fair value of contracts outstanding at beginning of period	**(13)**	17	(5)
Unrealized gain (loss) related to changes in the fair value of derivative instruments	**$132**	$(30)	$22

The sources of Sequent's net fair value at December 31, 2006 are as follows. The "prices actively quoted" category represents Sequent's positions in natural gas, which are valued exclusively using NYMEX futures prices. "Prices provided by other external sources" are basis transactions that represent the cost to transport the commodity from a NYMEX delivery point to the contract delivery point. Sequent's basis spreads are primarily based on quotes obtained either through electronic trading platforms or directly from brokers.

In millions	Prices actively quoted	Prices provided by other external sources
Mature through 2007	$21	$80
Mature 2008–2009	6	8
Mature 2010–2012	—	2
Mature after 2012	—	2
Total net fair value	$27	$92

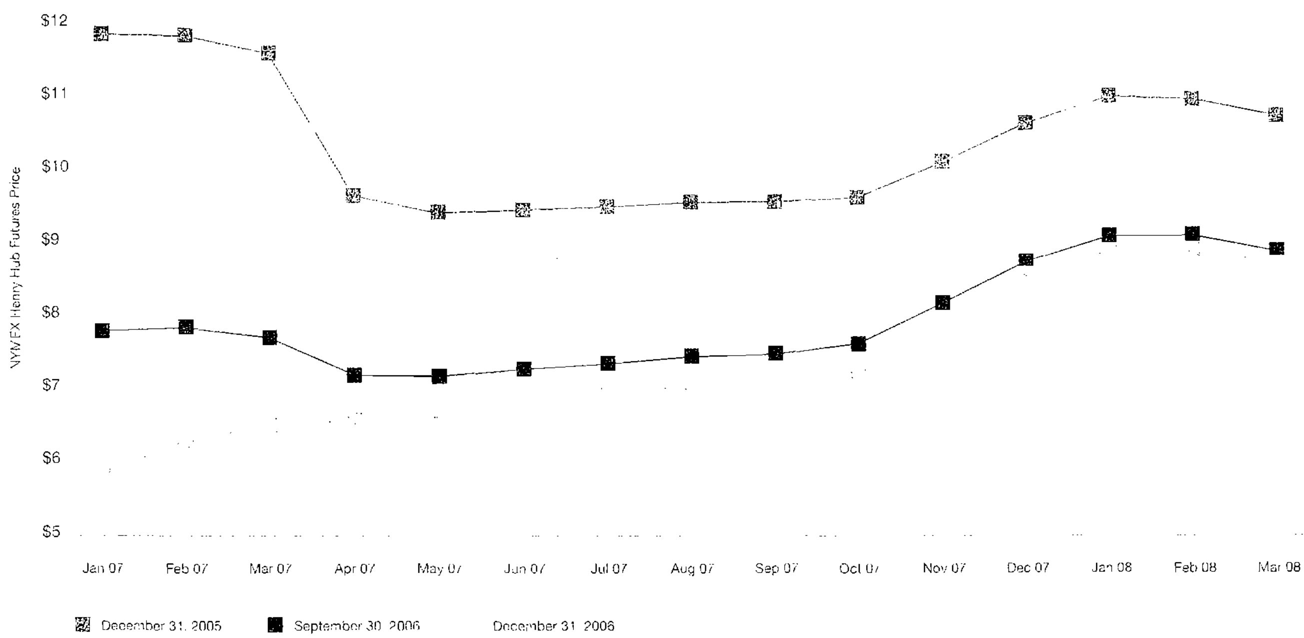
Mark-to-Market Versus Lower of Average Cost or Market » Sequent purchases natural gas for storage when the current market price it pays plus the cost for transportation and storage is less than the market price it could receive in the future. Sequent attempts to mitigate substantially all of the commodity price risk associated with its storage portfolio. Sequent uses derivative instruments to reduce the risk associated with future changes in the price of natural gas. Sequent sells NYMEX futures contracts or other over-the-counter derivatives in forward months to substantially lock in the profit margin it will ultimately realize when the stored gas is actually sold.

We view Sequent's trading margins from two perspectives. First, our commercial decisions are based on economic value, which is defined as the locked-in gain to be realized in the statement of income at the time the physical gas is withdrawn from storage and ultimately sold and the derivative instrument used to hedge natural gas price risk on that physical storage is settled. Second is the GAAP-reported value both prior to and at the point of physical withdrawal. The GAAP amount is impacted by the process of accounting for the financial hedging instruments in interim periods at fair value between the time the gas is injected into storage and when it is ultimately withdrawn and the financial instruments are settled. The change in the fair value of the hedging instruments is recognized in earnings in the period of change and is characterized as unrealized gains or losses.

Natural gas stored in inventory is accounted for differently than the derivatives Sequent uses to mitigate the commodity price risk associated with its storage portfolio. The natural gas that Sequent purchases and injects into storage is accounted for at the lower of average cost or current market value. The derivatives that Sequent uses to mitigate commodity price risk are accounted for at fair value and marked to market each period. This difference in accounting treatment can result in volatility in Sequent's reported results, even though the expected profit margin is essentially unchanged from the date the transactions were consummated. These accounting differences also affect the comparability of Sequent's period-over-period results, since changes in forward NYMEX prices do not increase and decrease on a consistent basis from year to year. During most of 2006, Sequent's reported results were positively impacted by decreases in forward NYMEX prices which resulted in the recognition of unrealized gains. In contrast, during most of 2005, Sequent's reported results were negatively impacted by increases in forward NYMEX prices which resulted in the recognition of unrealized losses, although to a lesser extent. During 2004, the reported results were not as significantly affected by changes in forward NYMEX prices. As a result, unrealized gains during 2006 had a positive impact on the favorable variance between 2006 and 2005 and unrealized losses during 2005 had a negative impact on the favorable variance between 2005 and 2004.

Storage Inventory Outlook » The following graph presents the NYMEX forward natural gas prices as of December 31, 2005, September 30, 2006, and December 31, 2006 for the period of January 2007 through March 2008, and reflects the prices at which Sequent could buy natural gas at the Henry Hub for delivery in the same time period.

NYMEX Forward Curve



Sequent's expected withdrawals from physical salt-dome and reservoir storage are presented in the table below along with the expected gross margin. Sequent's expected gross margin is net of the impact of regulatory sharing and reflects the amounts that it would expect to realize in future periods based on the inventory withdrawal schedule and forward natural gas prices at December 31, 2006. Sequent's storage inventory is hedged with futures, and as shown below, the NYMEX short positions are equal to the physical long positions, which results in an overall locked-in margin, timing notwithstanding. Sequent's physical salt-dome and reservoir volumes are presented in NYMEX equivalent contract units of 10,000 million British thermal units (MMBtu).

	Q1 2007	Q2 2007	Q3 2007	Q4 2007	Q1 2008	Total
Salt-dome	412	—	—	—	7	419
Reservoir	850	1	—	96	116	1,063
Total volumes	1,262	1	—	96	123	1,482
Expected gross margin (in millions)	$9	$—	$—	$4	$5	$18

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As of December 31, 2006, the weighted average cost of natural gas in inventory was $5.52 for physical salt-dome storage and $5.18 for physical reservoir storage. These costs reflect adjustments that were recorded at the end of each quarter in 2006 in order to reduce the value of Sequent's natural gas inventory to market value at certain locations. Sequent reduced the inventory value by $9 million after regulatory sharing for the quarter ended December 31 and by $43 million for the year ended December 31, 2006. These adjustments negatively impacted Sequent's reported earnings. However, as the carrying value of the inventory was reduced, the expected gross margin in the table above increased by an equal and offsetting amount. Sequent recovered $22 million of the aggregate $43 million of gross margin reductions during 2006 and expects to recover the majority of the remainder during the first quarter of 2007, as both the inventory is withdrawn from storage and sold and the hedging instruments in place to lock in the original margins on the storage transactions are settled and recorded in our earnings.

Park and Loan Transactions » Sequent routinely enters into park and loan transactions with various pipelines which allow it to park gas on or borrow gas from the pipeline in one period and reclaim gas from or repay gas to the pipeline in a subsequent period. The economics of these transactions are evaluated and price risks are managed in much the same way traditional reservoir and salt-dome storage transactions are evaluated and managed.

During the spring and summer months of 2006, natural gas prices were significantly lower than the futures prices for the upcoming winter months. As a result, Sequent has entered into transactions to park natural gas with the pipelines during the summer and receive the natural gas back during the winter.

Sequent enters into forward NYMEX contracts to hedge its park and loan transactions. While the hedging instruments mitigate the price risk associated with the delivery and receipt of natural gas, they can also result in volatility in Sequent's reported results during the period before the initial delivery or receipt of natural gas. During this period, if the forward NYMEX prices in the months of delivery and receipt do not change in equal amounts, Sequent will report a net unrealized gain or loss on the hedges.

Although Sequent's quarterly results were modestly impacted by unrealized hedge losses during 2006, on an annual basis Sequent did not report any significant gains or losses on park and loan hedges during 2006, 2005, or 2004.

Results of Operations » The following table presents results of operations for wholesale services for the years ended December 31, 2006, 2005, and 2004.

In millions	2006	2005	2004
Operating revenues	$182	$95	$54
Cost of sales	43	3	1
Operating margin[1]	139	92	53
Operating expenses	49	42	29
Operating income	90	50	24
Other expenses	—	(1)	—
EBIT[1]	$ 90	$49	$24
Metrics			
Physical sales volumes (Bcf/day)	2.20	2.17	2.10

[1] These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in "Results of Operations - AGL Resources."

The following table indicates the significant changes in operating margin for the years ended December 31, 2006, 2005 and 2004:

In millions	2006	2005	2004
Gain (loss) on storage hedges	$ 41	$ (7)	$ 5
Gain on transportation hedges	12	—	—
Commercial activity	107	102	49
Inventory LOCOM, net of hedging recoveries	(21)	(3)	(1)
Operating margin	$139	$ 92	$53

2006 compared to 2005 » The increase in EBIT of $41 million or 84% in 2006 compared to 2005 was primarily due to an increase in operating margin of $47 million partially offset by an increase in operating expenses of $7 million.

Sequent's operating margin increased by $47 million or 51% primarily due to improved commercial opportunities associated with larger seasonal storage spreads during the first half of 2006 and above-average temperatures during the late summer months. These conditions offset the impacts of mild weather during the winter and early summer and the lower level of market volatility that we experienced compared to the hurricane activity in the Gulf of Mexico in 2005.

Additionally, the 2006 reported results were positively impacted by forward NYMEX prices moving downward and the narrowing of future seasonal spreads which resulted in the recognition of $41 million of gains on Sequent's economic storage hedges in contrast to the prior period when forward prices increased and resulted in the recognition of $7 million of hedge losses. During 2006, Sequent also recognized $12 million in gains associated with financial instruments used to hedge its transportation capacity. There were no significant gains or losses associated with transportation hedges recognized in the prior period.

The positive impact from the price movements in 2006 was partially offset by LOCOM adjustments that Sequent recorded at certain storage locations during the year in order to reduce the carrying value of its natural gas inventory to current market prices. In 2006, Sequent recorded a total of $43 million in LOCOM adjustments: however $22 million of the adjustments were recovered during the period as the affected inventory was withdrawn from storage and sold and the hedging instruments in place to lock in the original margins on the storage transactions were settled. In 2005, Sequent recorded LOCOM adjustments of $3 million.

Operating expenses increased by $7 million or 17% primarily due to higher costs associated with an increase in the number of employees to support Sequent's growth and additional incentive compensation costs directly related to stronger financial performance in 2006, as well as a higher percentage of corporate overhead costs than in 2005, primarily due to Sequent's growth. The increased expenses were partially offset by lower costs associated with outside services and other expenses.

2005 compared to 2004 » The increase in EBIT of $25 million or 104% in 2005 compared to 2004 was primarily due to an increase in operating margin of $39 million partially offset by an increase in operating expenses of $13 million.

Sequent's operating margin increased by $39 million or 74% primarily due to the significant effects of the Gulf Coast hurricanes during the third quarter of 2005 and lingering market disruptions and price volatility throughout the fourth quarter. For the first nine months of the year, reported operating margins were similar to that of the prior year, with quarterly decreases being offset by quarterly increases. However, during the third quarter of 2005, while Sequent created substantial economic value by serving its customers during the storms, the reported operating margin was negatively impacted by accounting losses associated with storage hedges as a result of increases in forward NYMEX prices of approximately $6 per MMBtu. During the fourth quarter, natural gas prices continued to be volatile in the aftermath of the hurricanes and Sequent was able to further optimize its storage and transportation positions at levels in excess of the prior year. In addition, previously reported hedge losses were partially recovered during the fourth quarter as NYMEX prices decreased approximately $3 per MMBtu.

Operating expenses increased by $13 million or 45% due to additional payroll associated with increased headcount and increased employee incentive compensation costs driven by Sequent's operational and financial growth and depreciation expense in connection with a new ETRM system, which was implemented during the fourth quarter of the prior year.

Energy Investments

Jefferson Island » This wholly owned subsidiary operates a salt-dome storage and hub facility in Louisiana, approximately eight miles from the Henry Hub. The storage facility is regulated by the Louisiana Department of Natural Resources (Louisiana DNR) and by the FERC which has limited regulatory authority over the storage and transportation services. The facility consists of two salt-dome gas storage caverns with approximately 9.72 Bcf of total capacity and about 7.23 Bcf of working gas capacity. The facility has approximately 0.72 Bcf/day withdrawal capacity and 0.36 Bcf/day injection capacity. Jefferson Island provides storage and hub services through its direct connection to the Henry Hub via the Sabine Pipeline and its interconnection with seven other pipelines in the area. Jefferson Island's entire portfolio is under firm subscription for the 2006–2007 winter period.

In August 2006, the Office of Mineral Resources of the Louisiana DNR informed Jefferson Island that its mineral lease—which authorizes salt extraction to create two new storage caverns—at Lake Peigneur had been terminated. The Louisiana DNR identified two bases for the termination: (1) failure to make certain mining leasehold payments in a timely manner, and (2) the absence of salt mining operations for six months.

In September 2006, Jefferson Island filed suit against the State of Louisiana to maintain its lease to complete an ongoing natural gas storage expansion project in Louisiana. The project would add two salt-dome storage caverns under Lake Peigneur to the two caverns currently owned and operated by Jefferson Island. In its suit, Jefferson Island alleges that the Louisiana DNR accepted all leasehold payments without reservation and never provided Jefferson Island with notice and opportunity to cure, as required by state law. In its answer to the suit, the State denied that anyone with proper authority approved late payments. As to the second basis for termination, the suit contends that Jefferson Island's lease with the State of Louisiana was amended in 2004 so that mining operations are no longer required to maintain the lease. The State's answer denies that the 2004 amendment was properly authorized. We continue to seek resolution of this dispute and we are optimistic that a settlement can be reached with the State of Louisiana that would allow us to proceed with the expansion. If we are unable to reach a settlement, we are not able to predict the outcome of the litigation. As of January 2007, our current estimate of costs incurred that would be considered unusable if the Louisiana DNR was successful in terminating our lease and causing us to cease the expansion project is approximately $8 million.

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Golden Triangle Storage » In December 2006, we announced plans to build an approximate $180 million natural gas storage facility in the Beaumont, Texas area in the Spindletop salt dome. The project will consist of two underground salt-dome storage caverns approximately a half-mile to a mile below ground that will hold about 12 Bcf of working natural gas, or 17 Bcf total storage capacity. Golden Triangle Storage expects to finalize engineering plans and obtain regulatory permits to begin construction in 2008. The first salt-dome cavern is expected to begin operations in 2010, and the second cavern is expected to begin operations in 2012.

Pivotal Propane » In 2005, this wholly owned subsidiary completed the construction of a propane air facility in the Virginia Natural Gas service area that provides up to 0.03 Bcf/day of propane air on a 10-day-per-year basis to serve Virginia Natural Gas' peaking needs.

AGL Networks » This wholly owned subsidiary provides telecommunications conduit and dark fiber. AGL Networks leases and sells its fiber to a variety of customers in the Atlanta, Georgia and Phoenix, Arizona metropolitan areas, with a small presence in other cities in the United States. Its customers include local, regional and national telecommunications companies, internet service providers, educational institutions and other commercial entities. AGL Networks typically provides underground conduit and dark fiber to its customers under leasing arrangements with terms that vary from one to twenty years. In addition, AGL Networks offers telecommunications construction services to companies. AGL Networks' competitors are any entities that have laid or will lay conduit and fiber on the same route as AGL Networks in the respective metropolitan areas.

Results of Operations » The following table presents results of operations for energy investments for the years ended December 31, 2006, 2005 and 2004.

In millions	2006	2005	2004
Operating revenues	$41	$56	$25
Cost of sales	5	16	12
Operating margin[1]	36	40	13
Operating expenses	26	23	8
Operating income	10	17	5
Other income	—	2	2
EBIT[1]	$10	$19	$ 7

[1] These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in "Results of Operations – AGL Resources."

2006 compared to 2005 » The $9 million or 47% decrease in EBIT is due primarily to the loss of operating margin and other income contributions from the 2005 sale of certain assets that we originally acquired with the 2004 acquisition of NUI and an increase in operating expenses due to higher business development expenses and increased costs at Jefferson Island offset by lower expenses related to the sale of the former NUI assets in 2005.

Operating margin decreased $4 million or 10% largely due to the loss of $9 million of operating margin contributions from certain assets we acquired with the 2004 acquisition of NUI but sold in 2005. Jefferson Island's operating margin increased by $1 million compared to the prior year, in part due to increases in both firm and interruptible margin opportunities. AGL Networks' operating margin increased by $1 million due to a larger customer base. Pivotal Propane contributed a $2 million increase primarily in the first quarter of 2006 as it did not become operational until April 2005.

Operating expenses increased $3 million or 13% compared to 2005. Operating expenses at Pivotal Propane increased as it did not become operational until April 2005. Jefferson Island's operating expenses increased by $2 million due to the installation of new compression equipment and higher legal costs and property taxes. Additionally, project and corporate development costs increased $9 million. These costs were offset by decreased operating expenses of $8 million resulting from the 2005 sale of certain assets that we originally acquired with the 2004 acquisition of NUI. Other income decreased by $2 million due to the loss of earnings contributions from certain assets we acquired with the 2004 acquisition of NUI but sold in 2005.

2005 compared to 2004 » The $12 million or 171% increase in EBIT in 2005 was primarily the result of increased operating margin of $27 million, offset by $15 million in higher operating expenses.

Of the $27 million or 208% increase in operating margin, $13 million resulted from Jefferson Island, $8 million resulted from NUI's nonutility businesses and $3 million resulted from Pivotal Propane. AGL Networks contributed $4 million primarily as a result of recurring revenues from fiber leasing activities of $1 million and construction and new business activities of $3 million.

Of the $15 million or 188% increase in operating expenses, $8 million resulted from NUI's nonutility businesses, $3 million resulted from Jefferson Island and $3 million resulted from Pivotal Propane. AGL Networks' operating expenses were relatively flat in 2005 as compared to 2004.

Corporate

Our corporate segment includes our nonoperating business units, including AGL Services Company (AGSC) and AGL Capital Corporation (AGL Capital). AGL Capital provides for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities, and other financing arrangements.

Pivotal Energy Development coordinates among our related operating segments, the development, construction or acquisition of assets in the southeastern, mid-Atlantic and northeastern regions in order to extend our natural gas capabilities and improve system reliability while enhancing service to our customers in those areas. The focus of Pivotal Energy Development's commercial activities is to improve the economics of system reliability and natural gas deliverability in these targeted regions.

We allocate substantially all of AGSC's operating expenses and interest costs to our operating segments in accordance with various regulations. Our corporate segment also includes intercompany eliminations for transactions between our operating business segments. Our EBIT results include the impact of these allocations to the various operating segments. The acquisition of additional assets, such as NUI and Jefferson Island, typically enables us to allocate corporate costs across a larger number of businesses and, as a result, lower the relative allocations charged to those business units we owned prior to the acquisition of the new businesses.

Results of Operations » The following table presents results of operations tor our corporate segment for the years ended December 31, 2006, 2005 and 2004.

In millions	2006	2005	2004
Operating revenues	$(156)	$(182)	$(185)
Cost of sales	(157)	(182)	(184)
Operating margin[1,2]	1	—	(1)
Operating expenses[3]	9	6	12
Operating loss	(8)	(6)	(13)
Other expenses	(1)	(5)	(3)
EBIT[2]	$ (9)	$ (11)	$ (16)

[1] Includes intercompany eliminations.

[2] These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in "Results of Operations – AGL Resources."

[3] The following table summarizes the major components of operating expenses.

In millions	2006	2005	2004
Payroll	$ 55	$ 57	$ 48
Benefits and incentives	36	34	32
Outside services	41	43	29
All other expenses	50	57	50
Allocations	(173)	(185)	(147)
Total operating expenses	$ 9	$ 6	$ 12

The corporate segment is a nonoperating segment. As such, changes in EBIT amounts for the indicated periods reflect the relative changes in various general and administrative expenses, such as payroll, benefits and incentives, and outside services.

Liquidity and Capital Resources

To meet our capital and liquidity requirements we rely on operating cash flow; short-term borrowings under our commercial paper program, which is backed by our Credit Facility; borrowings under Sequent's and SouthStar's lines of credit; and borrowings or stock issuances in the long-term capital markets. Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including state public service commissions and the SEC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operation of our regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. The availability of borrowings under our Credit Facility is limited and subject to a total debt-to-capital ratio financial covenant specified within the Credit Facility, which we currently meet.

We will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by rating agencies and other factors. Additionally, our liquidity and capital resource requirements may change in the future due to a number of other factors, some of which we cannot control. These factors include:

- the seasonal nature of the natural gas business and our resulting short-term borrowing requirements, which typically peak during colder months
- increased gas supplies required to meet our customers' needs during cold weather
- changes in wholesale prices and customer demand for our products and services
- regulatory changes and changes in ratemaking policies of regulatory commissions
- contractual cash obligations and other commercial commitments
- interest rate changes
- pension and postretirement funding requirements
- changes in income tax laws
- margin requirements resulting from significant increases or decreases in our commodity prices
- operational risks
- the impact of natural disasters, including weather

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Contractual Obligations and Commitments » We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. The following table illustrates our expected future contractual obligations as of December 31, 2006.

			Payments due before December 31,		
In millions	Total	2007	2008 & 2009	2010 & 2011	2012 & thereafter
Interest charges[1]	$1,398	$ 99	$198	$ 177	$ 924
Pipeline charges, storage capacity and gas supply[2,3,4]	1,916	441	625	389	461
Long-term debt[5]	1,622	—	—	300	1,322
Short-term debt	539	539	—	—	—
PRP costs[6]	237	35	82	85	35
Operating leases[7]	170	32	47	34	57
ERC[6]	96	13	18	54	11
Total	$5,978	$1,159	$970	$1,039	$2,810

[1] Floating rate debt is based on the interest rate as of December 31, 2006 and the maturity of the underlying debt instrument.

[2] Charges recoverable through a PGA mechanism or alternatively billed to Marketers. Also includes demand charges associated with Sequent.

[3] A subsidiary of NUI entered into two 20-year agreements for the firm transportation and storage of natural gas during 200[illegible] with annual aggregate demand charges of approximately $5 million. As a result of our acquisition of NUI and in accordance with SFAS No. 141, "Business Combinations," we valued the contracts at fair value and established a long-term liability that will be amortized over the remaining lives of the contracts.

[4] Amount includes SouthStar gas commodity purchase commitments of 1.4 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2006, and is valued at $[illegible] million.

[5] Includes $77 million of notes payable to Trusts redeemable in 2007.

[6] Includes charges recoverable through rate rider mechanisms.

[7] We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with SFAS No. 13, "Accounting for Leases." However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein.

We calculate any required pension contributions using the projected unit credit cost method. Under this method, we were not required to make any pension contribution in 2006, but we voluntarily made a $5 million contribution in October 2006. See Note 4 "Employee Benefit Plans," for additional pension information.

We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The following table illustrates our expected contingent financial commitments as of December 31, 2006.

In millions	Total	2007	Commitments due before Dec. 31, 2008 and thereafter
Standby letters of credit, performance/surety bonds	$14	$12	$2

Cash Flow from Operating Activities » We prepare our statement of cash flows using the indirect method. Under this method, we reconcile net income to cash flows from operating activities by adjusting net income for those items that impact net income but do not result in actual cash receipts or payments during the period. These reconciling items include depreciation, changes in risk management assets and liabilities, undistributed earnings from equity investments, changes in deferred income taxes, gains or losses on the sale of assets and changes in the consolidated balance sheet for working capital from the beginning to the end of the period.

Year-over-year changes in our operating cash flows are attributable primarily to working capital changes within our distribution operations, wholesale services and retail energy operations segments resulting from the impact of weather, the price of natural gas, the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

We generate a large portion of our annual net income and subsequent increases in our accounts receivable in the first and fourth quarters of each year due to significant volumes of natural gas delivered by distribution operations and SouthStar to our customers during the peak heating season. In addition, our natural gas inventories, which usually peak on November 1, are largely drawn down in the heating season and provide a source of cash as this asset is used to satisfy winter sales demand.

During this period, our accounts payable increases to reflect payments due to providers of the natural gas commodity and pipeline capacity. The value of the natural gas commodity can vary significantly from one period to the next as a result of volatility in the price of natural gas. Our natural gas costs and deferred purchased natural gas costs due from or to our customers represent the difference between natural gas costs that we have paid to suppliers in the past and amounts that we have collected from customers. These natural gas costs can cause significant variations in cash flows from period to period.

In 2006, our net cash flow provided from operating activities was $354 million, an increase of $274 million or 343% from the same period of 2005. The increase was primarily a result of higher earnings in 2006 of $19 million, the recovery of working capital during 2006 that was deployed in 2005 due to the significantly higher commodity prices and the amount of working capital required during the last quarter of 2004 when prices were significantly lower. Contributing to this increase was a decrease in the amount of natural gas purchased for inventory at Sequent and our utilities of $157 million as a result of mild weather in the prior heating season and therefore higher inventory balances for the current heating season.

In 2005, our net cash flow provided from operating activities was $80 million, a decrease of $207 million or 72% from the same period of 2004. The decrease was primarily a result of increased working capital requirements including increased spending of $183 million for seasonal inventory injections in advance of the winter sales demand. We spent more on these injections in 2005 primarily because of higher natural gas prices due to the effects of the hurricanes in the Gulf Coast region and the full-year impact associated with the purchase of natural gas for the utilities acquired in November 2004 from NUI, principally Elizabethtown Gas. These higher natural gas prices resulted in a 45% increase in the average cost of our natural gas inventories.

Cash Flow from Investing Activities » Our investing activities consisted primarily of property, plant and equipment (PP&E) expenditures and our acquisitions of NUI for $116 million and Jefferson Island for $90 million in 2004. Additionally in 2006, we received approximately $5 million for the sale of land associated with former operating sites. In 2005, we sold our 50% interest in Saltville Gas Storage Company (Saltville) and associated subsidiaries for $66 million to a subsidiary of Duke Energy Corporation. We acquired Saltville through our acquisition of NUI. In 2004, we sold our general and limited partnership interests in US Propane LP which was a joint venture formed in 2000, for $31 million. The following table provides additional information on our actual and estimated PP&E expenditures.

In millions	2007[1]	**2006**	2005	2004
Construction or preservation of distribution facilities	$159	**$144**	$135	$64
Southern Natural Gas pipeline	—	**—**	32	—
PRP	35	**31**	48	95
Pivotal Propane plant	—	**—**	—	29
Jefferson Island	53	**20**	8	2
Telecommunications	3	**3**	1	5
Other[2]	28	**55**	43	69
Total	$278	**$253**	$267	$264

[1] Estimated

[2] Includes corporate information technology systems and infrastructure expenditures.

The decrease of $14 million or 5% in PP&E expenditures for 2006 compared to 2005 was primarily due to the $32 million acquisition of a 250-mile pipeline in Georgia from Southern Natural Gas (SNG) in 2005 and $7 million for construction of distribution facilities in Georgia. This was offset by higher expenditures of $8 million at the corporate segment primarily on information technology projects, $12 million at Jefferson Island on its expansion project and $5 million at retail energy operations primarily due to the implementation of a new energy trading and risk management (ETRM) system and enhancements to the retail billing system.

The increase of $3 million or 1% in PP&E expenditures for 2005 compared to 2004 was primarily due to the $32 million acquisition of the SNG pipeline in 2005 and increased expenditures of $71 million for the construction of distribution facilities, including $27 million at Elizabethtown Gas and Florida City Gas, both of which were acquired in November 2004. Also contributing to the increase was $6 million of additional expenditures at Jefferson Island which completed a capital project to improve its compression capabilities. These increases were offset by reduced PRP expenditures of $47 million due to the rate case settlement agreement between Atlanta Gas Light and the Georgia Commission that extended the program to 2013, reduced expenditures of $29 million at the Pivotal Propane plant in Virginia as most of its construction expenditures were incurred in 2004 and reduced expenditures at Sequent as its ETRM system was implemented in 2004.

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We expect our future PRP expenditures will primarily include larger-diameter pipe than in prior years, the majority of which is located in more densely populated areas. The following table provides more information on our expected PRP expenditures.

Year	Miles of pipe to be replaced	Expenditures (in millions)
2007	107	$ 35
2008	144	38
2009	147	44
2010–2013	337	120
Totals	735	$237

Cash Flow from Financing Activities » Our financing activities are primarily composed of borrowings and payments of short-term debt, payments of medium-term notes, borrowings of senior notes, distributions to minority interests, cash dividends on our common stock issuances, and purchases and issuances of treasury shares. Our capitalization and financing strategy is intended to ensure that we are properly capitalized with the appropriate mix of equity and debt securities. This strategy includes active management of the percentage of total debt relative to total capitalization, appropriate mix of debt with fixed to floating interest rates (our variable debt target is 25% to 45% of total debt), as well as the term and interest rate profile of our debt securities. As of December 31, 2006, our variable-rate debt was $733 million or 34% of our total debt. This included $527 million of variable-rate short-term debt, $100 million of variable-rate senior notes and $106 million of variable-rate gas facility revenue bonds. In 2005, our variable-rate debt was also 34% of our total debt.

We also work to maintain or improve our credit ratings on our debt to effectively manage our existing financing costs and enhance our ability to raise additional capital on favorable terms. Factors we consider important in assessing our credit ratings include our balance sheet leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any agreements that would require us to issue equity based on credit ratings or other trigger events. The table below summarizes our credit ratings as of December 31, 2006, which reflects no change from last year.

	S&P	Moody's	Fitch
Corporate rating	A-		
Commercial paper	A-2	P-2	F-2
Senior unsecured	BBB+	Baa1	A-
Ratings outlook	Negative	Stable	Stable

Our credit ratings may be subject to revision or withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating. We cannot ensure that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. If the rating agencies downgrade our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources would decrease.

Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include maintaining covenants with respect to a maximum leverage ratio, insolvency events, nonpayment of scheduled principal or interest payments, and acceleration of other financial obligations and change of control provisions. Our Credit Facility's financial covenant requires us to maintain a ratio of total debt to total capitalization of no greater than 70%; however, our goal is to maintain this ratio at levels between 50% and 60%. We are currently in compliance with all existing debt provisions and covenants. For more information on our debt, see Note 7 "Debt."

We believe that accomplishing these capitalization objectives and maintaining sufficient cash flow are necessary to maintain our investment-grade credit ratings and to allow us access to capital at reasonable costs. The components of our capital structure, as of the dates indicated, are summarized in the following tables.

In millions	Dec. 31, 2006	
Short-term debt	$ 539	14%
Long-term debt[1]	1,622	43
Total debt	2,161	57
Common shareholders' equity	1,609	43
Total capitalization	$3,770	100%

In millions	Dec. 31, 2005	
Short-term debt	$ 522	14%
Long-term debt[1]	1,615	45
Total debt	2,137	59
Common shareholders' equity	1,499	41
Total capitalization	$3,636	100%

[1] Net of interest rate swaps.

Short-term Debt » Our short-term debt is composed of borrowings under our commercial paper program, lines of credit at Sequent, SouthStar and Pivotal Utility, the current portion of our medium-term notes and the current portion of our capital leases. Our short-term debt financing generally increases between June and December because our payments for natural gas and pipeline capacity are generally made to suppliers prior to the collection of accounts receivable from our customers. We typically reduce short-term debt balances in the spring because a significant portion of our current assets are converted into cash at the end of the winter heating season.

In August 2006, we replaced our previous Credit Facility with a new Credit Facility that supports our commercial paper program. Under the terms of the new Credit Facility, the aggregate principal amount available has been increased from $850 million to $1 billion and we can request an option to increase the aggregate principal amount available for borrowing to $1.25 billion on not more than three occasions during each calendar year. This Credit Facility expires August 31, 2011. The increased capacity under our Credit Facility increases our ability to borrow under our commercial paper program. Our total cash and available liquidity under our Credit Facility as of the dates indicated are shown in the table below.

In millions	Dec. 31, 2006	Dec. 31, 2005
Unused availability under the Credit Facility	$1,000	$850
Cash and cash equivalents	20	32
Total cash and available liquidity under the Credit Facility	$1,020	$882

As of December 31, 2006 and 2005, we had no outstanding borrowings under the Credit Facility. However, the availability of borrowings and unused availability under our Credit Facility is limited and subject to conditions specified within the Credit Facility, which we currently meet. These conditions include:

- the maintenance of a ratio of total debt to total capitalization of no greater than 70%
- the continued accuracy of representations and warranties contained in the agreement

In 2006, we extended Sequent's two lines of credit through June 2007 and August 2007. In addition, we extended Pivotal Utility's line of credit through August 2007. These unsecured lines of credit are unconditionally guaranteed by us.

In November of 2006, SouthStar closed a five-year $75 million credit facility. This facility will be used for working capital needs and general corporate needs. At December 31, 2006, there were no outstanding borrowings on this line of credit.

Long-term Debt » In May 2006, we used the proceeds from the sale of commercial paper to redeem $150 million of junior subordinated debentures and to pay a $5 million note representing our investment in our Capital Trust, previously included in notes payable to trusts. In June 2006, we issued $175 million of 10-year senior notes at an interest rate of 6.375% and used the net proceeds of $173 million to repay the commercial paper. In January 2007, we used proceeds from the sale of commercial paper to redeem $11 million of 7% medium-term notes previously scheduled to mature in January 2015.

Interest Rate Swaps » To maintain an effective capital structure, it is our policy to borrow funds using a mix of fixed-rate debt and variable-rate debt. We have entered into interest rate swap agreements for the purpose of hedging the interest rate risk associated with our fixed-rate and variable-rate debt obligation.

Minority Interest » As a result of our consolidation of SouthStar's accounts effective January 1, 2004, we recorded Piedmont's portion of SouthStar's contributed capital as a minority interest in our consolidated balance sheets and included it as a component of our total capitalization. A cash distribution of $22 million in 2006, $19 million in 2005 and $14 million in 2004 for SouthStar's dividend distributions to Piedmont were recorded in our consolidated statement of cash flows as a financing activity.

Dividends on Common Stock » In 2006, we made $111 million in common stock dividend payments. This was an increase of $11 million or 11% from 2005, which resulted from increases in the amount of our quarterly common stock dividends per share. In 2005, we made $100 million in common stock dividend payments. This was an increase of $25 million or 33% from 2004. The increase was due to our 11 million share common stock offering in November 2004, which increased the number of shares outstanding, and the increases in the amount of our quarterly common stock dividends per share.

In the last three fiscal years, we have made the following increases in dividends on our common stock. For information about restrictions on our ability to pay dividends on our common stock, see Note 6.

Date of change	% increase	Quarterly dividend	Indicated annual dividend
Nov 2005	19%	$0.37	$1.48
Feb 2005	7	0.31	1.24
Apr 2004	4	0.29	1.16

Share Repurchases » In March 2001 our Board of Directors approved the purchase of up to 600,000 shares of our common stock to be used for issuances under the Officer Incentive Plan. During 2006, we purchased 32,801 shares. As of December 31, 2006, we had purchased a total 286,567 shares, leaving 313,433 shares available for purchase.

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In February 2006, our Board of Directors authorized a plan to purchase up to eight million shares of our outstanding common stock over a five-year period. These purchases are intended principally to offset share issuances under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this program may be made in the open market or in private transactions at times and in amounts that we deem appropriate. There is no guarantee as to the exact number of shares that we will purchase, and we can terminate or limit the program at any time. We will hold the purchased shares as treasury shares. During 2006, we repurchased 1,027,500 shares at a weighted average price of $36.67. For more information on our share repurchases see Item 5 "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities."

Shelf Registration » We currently have remaining capacity under an October 2004 shelf registration statement of approximately $782 million. We may seek additional financing through debt or equity offerings in the private or public markets at any time.

Critical Accounting Policies

The preparation of our financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, and we evaluate our estimates on an ongoing basis. Our actual results may differ from our estimates. Each of the following critical accounting policies involves complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements.

Pipeline Replacement Program » Atlanta Gas Light was ordered by the Georgia Commission (through a joint stipulation between Atlanta Gas Light and the Commission staff) to undertake a PRP that would replace all bare steel and cast iron pipe in its system in the state of Georgia within a 10-year period beginning October 1, 1998. Atlanta Gas Light identified and in accordance with this stipulation, provided notice to the Georgia Commission of 2,632 miles of bare steel and cast iron pipe to be replaced.

On June 10, 2005, the Georgia Commission approved a Settlement Agreement with Atlanta Gas Light that, among other things, extends Atlanta Gas Light's PRP by five years to require that all replacements be completed by December 2013. The timing of replacements was subsequently specified in an amendment to the PRP stipulation. This amendment, which was approved by the Georgia Commission on December 20, 2005, requires Atlanta Gas Light to replace all cast iron pipe and 70% of all bare steel pipe by December 2010. The remaining 30% of bare steel pipe is required to be replaced by December 2013. Approximately 131 miles of cast iron and 604 miles of bare steel pipe still require replacement. If Atlanta Gas Light does not perform in accordance with the initial and amended PRP stipulation, it can be assessed certain nonperformance penalties. However, to date, Atlanta Gas Light is in full compliance.

The stipulation also provides for recovery of all prudent costs incurred under the program, which Atlanta Gas Light has recorded as a regulatory asset. The regulatory asset has two components:

- the costs incurred to date that have not yet been recovered through rate riders
- the future expected costs to be recovered through rate riders

The determination of future expected costs involves judgment. Factors that must be considered in estimating the future expected costs are projected capital expenditure spending, including labor and material costs, and the remaining infrastructure footage to be replaced for the remaining years of the program. Atlanta Gas Light recorded a long-term liability of $202 million as of December 31, 2006 and $235 million as of December 31, 2005, which represented engineering estimates for remaining capital expenditure costs in the PRP. As of December 31, 2006, Atlanta Gas Light had recorded a current liability of $35 million, representing expected PRP expenditures for the next 12 months. We report these estimates on an undiscounted basis. If the recorded liability for PRP had been higher or lower by $10 million, Atlanta Gas Light's expected recovery would have changed by approximately $1 million.

Environmental Remediation Liabilities » Atlanta Gas Light historically reported estimates of future remediation costs based on probabilistic models of potential costs. We report these estimates on an undiscounted basis. As we continue to conduct the actual remediation and enter cleanup contracts, Atlanta Gas Light is increasingly able to provide conventional engineering estimates of the likely costs of many elements of its remediation program. These estimates contain various engineering uncertainties, and Atlanta Gas Light continuously attempts to refine and update these engineering estimates.

Our latest available estimate as of December 31, 2006 for those elements of the remediation program with in-place contracts or engineering cost estimates is $13 million for Atlanta Gas

Light's Georgia and Florida sites. This is an increase of $1 million from the December 31, 2005 estimate of projected engineering and in-place contracts, resulting from increased cost estimates during 2006. For elements of the remediation program where Atlanta Gas Light still cannot perform engineering cost estimates, considerable variability remains in available estimates. The estimated remaining cost of future actions at these sites is $14 million. Atlanta Gas Light estimates certain other costs it pays related to administering the remediation program and remediation of sites currently in the investigation phase. Beyond 2008, these costs cannot be estimated.

Atlanta Gas Light's environmental remediation liability is included in its corresponding regulatory asset. As of December 31, 2006, the regulatory asset was $104 million, which is a combination of the accrued remediation liability and unrecovered cash expenditures. Atlanta Gas Light's estimate does not include other potential expenses, such as unasserted property damage, personal injury or natural resource damage claims, unbudgeted legal expenses, or other costs for which it may be held liable but with respect to which the amount cannot be reasonably forecast. Atlanta Gas Light's recovery of environmental remediation costs is subject to review by the Georgia Commission which may seek to disallow the recovery of some expenses.

In New Jersey, Elizabethtown Gas is currently conducting remediation activities with oversight from the New Jersey Department of Environmental Protection. Although the actual total cost of future environmental investigation and remediation efforts cannot be estimated with precision, the range of reasonably probable costs is $60 million to $118 million. As of December 31, 2006, we have recorded a liability of $60 million.

The New Jersey Commission has authorized Elizabethtown Gas to recover prudently incurred remediation costs for the New Jersey properties through its remediation adjustment clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $66 million, inclusive of interest, as of December 31, 2006, reflecting the future recovery of both incurred costs and future remediation liabilities in the state of New Jersey. Elizabethtown Gas has also been successful in recovering a portion of remediation costs incurred in New Jersey from its insurance carriers and continues to pursue additional recovery. As of December 31, 2006, the variation between the amounts of the environmental remediation cost liability recorded in the consolidated balance sheet and the associated regulatory asset is due to expenditures for environmental investigation and remediation exceeding recoveries from ratepayers and insurance carriers.

We also own several former NUI remediation sites located outside of New Jersey. One site, in Elizabeth City, North Carolina, is subject to an order by the North Carolina Department of Environment and Natural Resources. Preliminary estimates for investigation and remediation costs range from $10 million to $17 million. As of December 31, 2006, we had recorded a liability of $10 million related to this site. There is another site in North Carolina where investigation and remediation is probable, although no regulatory order exists and we do not believe costs associated with this site can be reasonably estimated. In addition, there are as many as six other sites with which NUI had some association, although no basis for liability has been asserted. We do not believe that costs to investigate and remediate these sites, if any, can be reasonably estimated at this time.

With respect to these costs, we currently pursue or intend to pursue recovery from ratepayers, former owners and operators and insurance carriers. Although we have been successful in recovering a portion of these remediation costs from our insurance carriers, we are not able to express a belief as to the success of additional recovery efforts. We are working with the regulatory agencies to prudently manage our remediation costs so as to mitigate the impact of such costs on both ratepayers and shareholders.

Derivatives and Hedging Activities » SFAS 133, as updated by SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149), established accounting and reporting standards which require that every derivative financial instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. However, if the derivative transaction qualifies for and is designated as a normal purchase and sale, it is exempted from the fair value accounting treatment of SFAS 133, as updated by SFAS 149, and is accounted for using traditional accrual accounting.

SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, SFAS 133 allows a derivative's gains and losses to offset related results on the hedged item in the income statement in the case of a fair value hedge, or to record the gains and losses in OCI until maturity in the case of a cash flow hedge. Additionally, SFAS 133 requires that a company formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment. SFAS 133 applies to Treasury Locks and interest rate swaps executed by AGL Capital and gas commodity contracts executed by both Sequent and SouthStar. Our derivative and hedging activities are

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described in further detail in Note 1, "Accounting Policies and Methods of Application," Note 2 "Risk Management" and Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Commodity-related Derivative Instruments ›› We are exposed to risks associated with changes in the market price of natural gas. Through Sequent and SouthStar, we use derivative instruments to reduce our exposure to the risk of changes in the price of natural gas.

Sequent recognizes the change in value of derivative instruments as an unrealized gain or loss in revenues in the period when the market value of the instrument changes. Sequent recognizes cash inflows and outflows associated with the settlement of its risk management activities in operating cash flows, and reports these settlements as receivables and payables in the balance sheet separately from the risk management activities reported as energy marketing receivables and trade payables.

We attempt to mitigate substantially all our commodity price risk associated with Sequent's natural gas storage portfolio and lock in the economic margin at the time we enter into purchase transactions for our stored natural gas. We purchase natural gas for storage when the current market price we pay plus storage costs is less than the market price we could receive in the future. We lock in the economic margin by selling NYMEX futures contracts or other over-the-counter derivatives in the forward months corresponding with our withdrawal periods. We use contracts to sell natural gas at that future price to substantially lock in the profit margin we will ultimately realize when the stored natural gas is actually sold. These contracts meet the definition of a derivative under SFAS 133.

The purchase, storage and sale of natural gas are accounted for differently from the derivatives we use to mitigate the commodity price risk associated with our storage portfolio. The difference in accounting can result in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated. We do not currently use hedge accounting under SFAS 133 to account for this activity.

Natural gas that we purchase and inject into storage is accounted for at the lower of average cost or market. Under current accounting guidance, we would recognize a loss in any period when the market price for natural gas is lower than the carrying amount of our purchased natural gas inventory. Costs to store the natural gas are recognized in the period the costs are incurred. We recognize revenues and cost of natural gas sold in our statement of consolidated income in the period we sell gas and it is delivered out of the storage facility.

The derivatives we use to mitigate commodity price risk and substantially lock in the margin upon the sale of stored natural gas are accounted for at fair value and marked to market each period, with changes in fair value recognized as unrealized gains or losses in the period of change. This difference in accounting, the lower of average cost or market basis for our storage inventory versus the fair value accounting for the derivatives used to mitigate commodity price risk, can and does result in volatility in our reported earnings.

Over time, gains or losses on the sale of storage inventory will be substantially offset by losses or gains on the derivatives, resulting in realization of the economic profit margin we expected when we entered into the transactions. This accounting difference causes Sequent's earnings on its storage positions to be affected by natural gas price changes, even though the economic profits remain essentially unchanged.

See "Results of Operations—Wholesale Services" for a discussion of the potential volatility in earnings due to changes in natural gas prices.

SouthStar also uses derivative instruments to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to minimize volatility in wholesale commodity natural gas prices. A portion of SouthStar's derivative transactions are designated as cash flow hedges under SFAS 133. Derivative gains or losses arising from cash flow hedges are recorded in OCI and are reclassified into earnings in the same period the underlying hedged item is reflected in the income statement. As of December 31, 2006, the ending balance in OCI for derivative transactions designated as cash flow hedges under SFAS 133 was a gain of $6 million, net of minority interest and taxes. Any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not offset the losses or gains on the hedged item, is recorded into earnings in the period in which it occurs. SouthStar currently has minimal hedge ineffectiveness. SouthStar's remaining derivative instruments are not designated as hedges under SFAS 133. Therefore, changes in their fair value are recorded in earnings in the period of change.

SouthStar also enters into weather derivative instruments in order to preserve margins in the event of warmer-than-normal weather in the winter months. These contracts are accounted for using the intrinsic value method under the guidance of EITF Issue No. 99-02, "Accounting for Weather Derivatives." Changes in the fair value of these derivatives are recorded in earnings in the period of change. The weather derivative contracts contain strike amount provisions based on cumulative heating degree days for the covered periods. In September 2006, SouthStar entered into weather derivatives (swaps and options) for the 2006–2007 winter heating season, primarily from November through March. As of December 31, 2006, SouthStar recorded a receivable of $7 million for this hedging activity.

Contingencies » Our accounting policies for contingencies cover a variety of business activities, including contingencies for potentially uncollectible receivables, rate matters, and legal and environmental exposures. We accrue for these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated in accordance with SFAS No. 5, "Accounting for Contingencies." We base our estimates for these liabilities on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Actual results may differ from estimates, and estimates can be, and often are, revised either negatively or positively, depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure.

Pension and Other Postretirement Plans » Our pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. We annually review the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities. The assumed discount rate and the expected return on plan assets are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and the assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is used principally to calculate the actuarial present value of our pension and postretirement obligations and net pension and postretirement cost. When establishing our discount rate, we consider high-quality corporate bond rates based on Moody's Corporate AA long-term bond rate of 5.8% and the Citigroup Pension Liability rate of 5.9% at December 31, 2006. We further use these market indices as a comparison to a single equivalent discount rate derived with the assistance of our actuarial advisors. This analysis as of December 31, 2006 produced a single equivalent discount rate of 5.8%.

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, or longer or shorter life spans of participants. These differences may result in a significant impact on the amount of pension expense recorded in future periods.

The expected long-term rate of return on assets is used to calculate the expected return on plan assets component of our annual pension and postretirement plan cost. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan cost is not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan costs.

Prior to 2006, we estimated the assumed health care cost trend rate used in determining our postretirement net expense based on our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. However, starting in 2006, our postretirement plans have been capped at 2.5% for increases in health care costs. Consequently, a one-percentage-point increase or decrease in the assumed health care trend rate does not materially affect the periodic benefit cost for our postretirement plans. A one-percentage-point increase in the assumed health care cost trend rate would increase our accumulated projected benefit obligation by $4 million. A one-percentage-point decrease in the assumed health care cost trend rate would decrease our accumulated projected benefit obligation by $4 million. Our assumed rate of retirement is estimated based upon an annual review of participant census information as of the measurement date.

At December 31, 2006, our pension and postretirement liability decreased by approximately $18 million, resulting in an after-tax gain to OCI of $11 million. This adjustment reflected our funding contributions to the plan and updated valuations for the projected benefit obligation (PBO) and plan assets.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded accumulated benefit obligation (ABO), as the primary factors that drive the value of our unfunded ABO are the assumed discount rate and the actual return on plan assets. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes differences between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year moving weighted average methodology. Gains and losses on plan assets

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are spread through the MRVPA based on the five-year moving weighted average methodology, which affects the expected return on plan assets component of pension expense.

The actual return on our pension plan assets compared to the expected return on plan assets will have an impact on our ABO as of December 31, 2006 and our pension expense for 2007. We are unable to determine how this actual return on plan assets will affect future ABO and pension expense, as actuarial assumptions and differences between actual and expected returns on plan assets are determined at the time we complete our actuarial evaluation as of December 31, 2006. Our actual returns may also be positively or negatively impacted as a result of future performance in the equity and bond markets. The following tables illustrate the effect of changing the critical actuarial assumptions, as discussed above, while holding all other assumptions constant:

AGL Resources Inc. Retirement and Postretirement Plans

In millions Actuarial assumptions	Percentage point change in assumption	Increase (decrease) in ABO	Pension benefits increase (decrease) in cost	Increase (decrease) in obligation	Health and life benefits Increase (decrease) in cost
Expected long-term return on plan assets	+/- 1%	$ —/—	$(3)/3		
Discount rate	+/- 1%	(40)/45	(4)/4		
Health care cost trend rate	+/- 1%			$4/(4)	$—/—

NUI Corporation Retirement Plan

In millions Actuarial assumptions	Percentage point change in assumption	Increase (decrease) in ABO	Pension benefits increase (decrease) in cost
Expected long-term return on plan assets	+/- 1%	$—/—	$ (1)/1
Discount rate	+/- 1%	(8)/8	—/—

At December 31, 2006 NUI's PBO was $86 million, reflecting $12 million in adjustments for terminations and settlement of liabilities affected by the NUI purchase transaction, offset by net periodic benefit cost of $3 million in 2006. Differences between actuarial assumptions and actual plan results are deferred and amortized into cost when the accumulated differences exceed 10% of the greater of the PBO or the MRVPA. If necessary, the excess is amortized over the average remaining service period of active employees.

In addition to the assumptions listed above, the measurement of the plans' obligations and costs depend on other factors such as employee demographics, the level of contributions made to the plans, earnings on the plans' assets and mortality rates.

Income Taxes » Our net long-term deferred tax liability totaled $544 million at December 31, 2006 (see Note 10 "Income Taxes"). This liability is estimated based on the expected future tax consequences of items recognized in the financial statements. After application of the federal statutory tax rate to book income, judgment is required with respect to the timing and deductibility of expense in our income tax returns. For state income tax and other taxes, judgment is also required with respect to the apportionment among the various jurisdictions. A valuation allowance is recorded if we expect that it is more likely than not that our deferred tax assets will not be realized. We had a $3 million valuation allowance on $47 million of deferred tax assets as of December 31, 2006, reflecting the expectation that most of these assets will be realized. In addition, we maintain a liability for the estimate of potential income tax exposure. We believe this liability for potential exposure to be adequate.

Accounting Developments

For information regarding accounting developments, see Note 1, "Accounting Policies and Methods of Application."

Item 7a » Quantitative and Qualitative Disclosures about Market Risk

We are exposed to risks associated with commodity prices, interest rates and credit. Commodity price risk is defined as the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services.

Our Risk Management Committee (RMC) is responsible for establishing the overall risk management policies and monitoring compliance with, and adherence to, the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of members of senior management who monitor open commodity price risk positions and other types of risk, corporate exposures, credit exposures and overall results of our risk management activities. It is chaired by our chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions. Our risk management activities and related accounting treatments are described in further detail in Note 2, "Risk Management."

Commodity Price Risk

Retail Energy Operations » SouthStar's use of derivatives is governed by a risk management policy, approved and monitored by its Risk and Asset Management Committee, which prohibits the use of derivatives for speculative purposes. A 95% confidence interval is used to evaluate VaR exposure. A 95% confidence interval means there is a 5% probability that the actual change in portfolio value will be greater than the calculated VaR value over the holding period. We calculate VaR based on the variance-covariance technique. This technique requires several assumptions for the basis of the calculation, such as price volatility, confidence interval and holding period. Our VaR may not be comparable to a similarly titled measure of another company because, although VaR is a common metric in the energy industry, there is no established industry standard for calculating VaR or for the assumptions underlying such calculations. The following table provides more information on SouthStar's 1-day holding period VaR.

In millions	1 day
2006 period end	**$0.1**
2005 period end	0.3

SouthStar generates operating margin from the active management of storage positions through a variety of hedging transactions and derivative instruments aimed at managing exposures arising from changing commodity prices. SouthStar uses these hedging instruments to lock in economic margins as wholesale prices fluctuate and thereby minimize its exposure to declining operating margins.

Wholesale Services » Sequent routinely utilizes various types of financial and other instruments to mitigate certain commodity price risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and over-the-counter energy contracts, such as forward contracts, futures contracts, options contracts and financial swap agreements. The following table includes the fair values and average values of Sequent's energy marketing and risk management assets and liabilities as of December 31, 2006 and 2005. Sequent bases the average values on monthly averages for the 12 months ended December 31, 2006 and 2005.

	Average values at December 31,	
In millions	2006	2005
Asset	**$95**	$ 83
Liability	**43**	102

	Fair value at December 31,	
In millions	2006	2005
Asset	**$133**	$ 97
Liability	**14**	110

Sequent employs a systematic approach to evaluating and managing the risks associated with contracts related to wholesale marketing and risk management, including VaR. Similar to SouthStar, Sequent uses a 1-day holding period and a 95% confidence interval to evaluate its VaR exposure.

Sequent's open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management, including the chief risk officer. Because Sequent generally manages physical gas assets and economically protects its positions by hedging in the futures and over-the-counter markets, its open exposure is generally minimal, permitting Sequent to operate within relatively low VaR limits. Sequent employs daily risk testing, using both VaR and stress testing, to evaluate the risks of its open positions.

Sequent's management actively monitors open commodity positions and the resulting VaR. Sequent continues to maintain a relatively matched book, where its total buy volume is close to its sell volume, with minimal open commodity risk. Based on a 95% confidence interval and employing a 1-day holding period for all positions, Sequent's portfolio of positions for the 12 months ended December 31, 2006, 2005 and 2004 had the following 1-day holding period VaRs.

In millions	2006	2005	2004
Period end	**$1.3**	$0.6	$0.1
12-month average	**1.2**	0.4	0.1
High	**2.5**	1.1	0.4
Low[1]	**0.7**	0.0	0.0

[1] $0.0 values represent amounts less than $0.1 million.

During most of 2005 and 2006, Sequent experienced increases in its high, average and period end 1-day VaR amounts compared to prior periods. These increases were directly associated with higher prices and related price volatility created by the Gulf Coast hurricanes during the third quarter of 2005 and the hurricanes' lingering effects through the fourth quarters of 2005 and into 2006. In addition, Sequent has entered into additional storage

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and transportation positions, some of which are longer dated and are not fully hedged due to a lack of liquidity in certain markets for the future periods. As a result, these positions have increased Sequent's reported VaR amounts.

Sequent has refined the methodology associated with its VaR calculation to incorporate dynamic volatility factors and to exclude interruptible transportation positions. These changes had somewhat offsetting effects as the dynamic volatility factors increased the VaR and the exclusion of interruptible transportation positions reduced the VaR. This new methodology was applied on a prospective basis beginning in the second quarter of 2006. While not considered material, Sequent's VaR amounts increased compared to prior periods as its calculation is now more sensitive to market volatility and the relative level of risk associated with increased storage and transportation positions. Due to the dynamic nature of measuring VaR, Sequent will continually evaluate the components of its VaR calculation and will make refinements as deemed necessary.

Interest Rate Risk

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. Our policy is to manage interest expense using a combination of fixed-rate and variable-rate debt. To facilitate the achievement of desired fixed-rate to variable-rate debt ratios, AGL Capital entered into interest rate swaps whereby it agreed to exchange, at specified intervals, the difference between fixed and variable amounts calculated by reference to agreed-on notional principal amounts. These swaps are designated to hedge the fair values of $100 million of the $300 million Senior Notes due in 2011.

Credit Risk

Distribution Operations » Atlanta Gas Light has a concentration of credit risk as it bills only 11 Marketers in Georgia for its services. The credit risk exposure to Marketers varies with the time of the year, with exposure at its lowest in the nonpeak summer months and highest in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of the natural gas commodity. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light. For 2006, the four largest Marketers based on customer count, one of which was SouthStar, accounted for approximately 36% of our consolidated operating margin and 47% of distribution operations' operating margin.

Several factors are designed to mitigate our risks from the increased concentration of credit that has resulted from deregulation. In addition to the security support described above, Atlanta Gas Light bills intrastate delivery service to Marketers in advance rather than in arrears. We accept credit support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers and corporate guarantees from investment-grade entities. The RMC reviews on a monthly basis the adequacy of credit support coverage, credit rating profiles of credit support providers and payment status of each Marketer. We believe that adequate policies and procedures have been put in place to properly quantify, manage and report on Atlanta Gas Light's credit risk exposure to Marketers.

Atlanta Gas Light also faces potential credit risk in connection with assignments to Marketers of interstate pipeline transportation and storage capacity. Although Atlanta Gas Light assigns this capacity to Marketers, in the event that a Marketer fails to pay the interstate pipelines for the capacity, the interstate pipelines would in all likelihood seek repayment from Atlanta Gas Light. The fact that some of the interstate pipelines require Marketers to maintain security for their obligations to the interstate pipelines arising out of the assigned capacity somewhat mitigates this risk.

Retail Energy Operations » SouthStar obtains credit scores for its firm residential and small commercial customers using a national credit reporting agency, enrolling only those customers that meet or exceed SouthStar's credit threshold. The average credit score of SouthStar's Georgia customers has increased 3% since 2004.

SouthStar considers potential interruptible and large commercial customers based on a review of publicly available financial statements and review of commercially available credit reports. Prior to entering into a physical transaction, SouthStar also assigns physical wholesale counterparties an internal credit rating and credit limit based on the counterparties' Moody's, S&P and Fitch ratings, commercially available credit reports and audited financial statements.

Wholesale Services » Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. Sequent also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When Sequent is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of Sequent's credit risk. Sequent also uses other netting agreements with certain counterparties with whom it conducts significant transactions.

Master netting agreements enable Sequent to net certain assets and liabilities by counterparty. Sequent also nets across product lines and against cash collateral provided the master netting and cash collateral agreements include such provisions. Additionally, Sequent may require counterparties to pledge additional collateral when deemed necessary. Sequent conducts credit evaluations and obtains appropriate internal approvals for its counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, Sequent requires credit enhancements by way of guaranty, cash deposit or letter of credit for transaction counterparties that do not meet the minimum ratings threshold.

Sequent, which provides services to Marketers and utility and industrial customers, also has a concentration of credit risk as measured by its 30-day receivable exposure plus forward exposure. As of December 31, 2006, Sequent's top 20 counterparties represented approximately 57% of the total counterparty exposure of $394 million, derived by adding together the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures.

As of December 31, 2006, Sequent's counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A-, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty's assigned internal rating is multiplied by the counterparty's credit exposure and summed for all counterparties. That sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following tables show Sequent's commodity receivable and payable positions as of December 31, 2006 and 2005.

	As of December 31,	
In millions	2006	2005
Gross receivables		
Receivables with netting agreements in place:		
Counterparty is investment grade	$359	$462
Counterparty is non-investment grade	62	66
Counterparty has no external rating	75	113
Receivables without netting agreements in place:		
Counterparty is investment grade	9	34
Amount recorded on balance sheet	$505	$675
Gross payables		
Payables with netting agreements in place:		
Counterparty is investment grade	$297	$456
Counterparty is non-investment grade	52	56
Counterparty has no external rating	156	255
Payables without netting agreements in place:		
Counterparty is investment grade	5	4
Counterparty has no external rating	—	4
Amount recorded on balance sheet	$510	$775

Sequent has certain trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, Sequent would need to post collateral to continue transacting business with some of its counterparties. Posting collateral would have a negative effect on our liquidity. If such collateral were not posted, Sequent's ability to continue transacting business with these counterparties would be impaired. If at December 31, 2006 Sequent's credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $10 million.

Item 8 » Financial Statements and Supplementary Data

Consolidated Balance Sheets—Assets

In millions	As of December 31, 2006	December 31, 2005
Current assets		
Cash and cash equivalents	$ 20	$ 32
Receivables		
Energy marketing	505	675
Gas	197	303
Unbilled revenues	172	246
Other	21	11
Less allowance for uncollectible accounts	(15)	(15)
Total receivables	880	1,220
Inventories		
Natural gas stored underground	568	509
Other	29	34
Total inventories	597	543
Energy marketing and risk management assets	159	103
Unrecovered environmental remediation costs—current portion	27	31
Unrecovered PRP costs—current portion	27	27
Other current assets	112	85
Total current assets	1,822	2,041
Property, plant and equipment		
Property, plant and equipment	4,976	4,791
Less accumulated depreciation	1,540	1,458
Property, plant and equipment—net	3,436	3,333
Deferred debits and other assets		
Goodwill	420	420
Unrecovered PRP costs	247	276
Unrecovered environmental remediation costs	143	165
Other	79	85
Total deferred debits and other assets	889	946
Total assets	$6,147	$6,320

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets—Liabilities and Capitalization

In millions, except share amounts	As of December 31, 2006	December 31, 2005
Current liabilities		
Short-term debt	$ 539	$ 522
Energy marketing trade payable	510	775
Accounts payable—trade	213	266
Accrued wages and salaries	50	43
Customer deposits	42	42
Energy marketing and risk management liabilities—current portion	41	117
Accrued interest	37	32
Accrued PRP costs—current portion	35	30
Deferred purchased gas adjustment	24	40
Accrued environmental remediation costs—current portion	13	13
Other current liabilities	123	88
Total current liabilities	1,627	1,968
Accumulated deferred income taxes	544	423
Long-term liabilities		
Accrued PRP costs	202	235
Accumulated removal costs	162	156
Accrued environmental remediation costs	83	84
Accrued pension obligations	78	88
Accrued postretirement benefit costs	32	50
Other long-term liabilities	146	164
Total long-term liabilities	703	777
Commitments and contingencies (see Note 8)		
Minority interest	42	38
Capitalization		
Long-term debt	1,622	1,615
Common shareholders' equity, $5 par value; 750 million shares authorized; 77.7 million and 77.8 million shares outstanding at December 31, 2006 and 2005	1,609	1,499
Total capitalization	3,231	3,114
Total liabilities and capitalization	$6,147	$6,320

See Notes to Consolidated Financial Statements.

Statements of Consolidated Income

In millions, except per share amounts	Years ended December 31 2006	2005	2004
Operating revenues	**$2,621**	$2,718	$1,832
Operating expenses			
Cost of gas	**1,482**	1,626	995
Operation and maintenance	**473**	477	377
Depreciation and amortization	**138**	133	99
Taxes other than income taxes	**40**	40	29
Total operating expenses	**2,133**	2,276	1,500
Operating income	**488**	442	332
Other expenses	**(1)**	(1)	—
Minority interest	**(23)**	(22)	(18)
Interest expense	**(123)**	(109)	(71)
Earnings before income taxes	**341**	310	243
Income taxes	**129**	117	90
Net income	**$ 212**	$ 193	$ 153
Per common share data			
Basic earnings per common share	**$ 2.73**	$ 2.50	$ 2.30
Diluted earnings per common share	**$ 2.72**	$ 2.48	$ 2.28
Cash dividends declared per common share	**$ 1.48**	$ 1.30	$ 1.15
Weighted average number of common shares outstanding			
Basic	**77.6**	77.3	66.3
Diluted	**78.0**	77.8	67.0

See Notes to Consolidated Financial Statements.

Statements of Consolidated Common Shareholders' Equity

In millions, except per share amounts	Common stock Shares	Common stock Amount	Premium on common stock	Earnings reinvested	Other comprehensive loss	Shares held in treasury and trust	Total
Balance as of December 31, 2003	64.5	$322	$326	$ 337	$(40)	—	$ 945
Comprehensive income:							
Net income	—	—	—	153	—	—	153
Other comprehensive income (OCI)—loss resulting from unfunded pension obligation (net of tax of $7)	—	—	—	—	(11)	—	(11)
Unrealized gain from equity investment hedging activities (net of tax of $2)	—	—	—	—	4	—	4
Other	—	—	—	—	1	—	1
Total comprehensive income							147
Dividends on common stock ($1.15 per share)	—	—	—	(75)	—	—	(75)
Issuance of common shares:							
Equity offering on November 24, 2004	11.0	55	277	—	—	—	332
Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax of $5)	1.2	7	29	—	—	—	36
Balance as of December 31, 2004	76.7	384	632	415	(46)	—	1,385
Comprehensive income:							
Net income	—	—	—	193	—	—	193
OCI—loss resulting from unfunded pension obligation (net of tax of $3)	—	—	—	—	(5)	—	(5)
Unrealized loss from hedging activities (net of tax of $1)	—	—	—	—	(2)	—	(2)
Total comprehensive income							186
Dividends on common stock ($1.30 per share)	—	—	—	(100)	—	—	(100)
Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax of $9)	1.1	5	23	—	—	—	28
Balance as of December 31, 2005	77.8	389	655	508	(53)	—	1,499
Comprehensive income:							
Net income	—	—	—	212	—	—	212
OCI—gain resulting from unfunded pension and postretirement obligation (net of tax of $7)	—	—	—	—	11	—	11
Unrealized gain from hedging activities (net of tax of $7)	—	—	—	—	10	—	10
Total comprehensive income							233
Dividends on common stock ($1.48 per share)	—	—	1	(115)	—	3	(111)
Benefit, dividend reinvestment and stock purchase plans	0.3	1	2	—	—	—	3
Issuance of treasury shares	0.6	—	(3)	(4)	—	21	14
Purchase of treasury shares	(1.0)	—	—	—	—	(38)	(38)
Stock-based compensation expense (net of tax of $5)	—	—	9	—	—	—	9
Balance as of December 31, 2006	77.7	$390	$664	$ 601	$(32)	$(14)	$1,609

See Notes to Consolidated Financial Statements

Statements of Consolidated Cash Flows

In millions	Years ended December 31, 2006	2005	2004
Cash flows from operating activities			
Net income	$ 212	$ 193	$ 153
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization	138	133	99
Minority interest	23	22	18
Change in risk management assets and liabilities	(130)	27	(32)
Deferred income taxes	133	17	65
Changes in certain assets and liabilities			
Receivables	340	(338)	(264)
Inventories	(54)	(211)	(28)
Payables	(318)	311	247
Other—net	12	(74)	29
Net cash flow provided by operating activities	354	80	287
Cash flows from investing activities			
Expenditures for property, plant and equipment	(253)	(267)	(264)
Sale of Saltville Gas Storage Company, LLC	—	66	—
Acquisition of NUI Corporation, net of cash acquired	—	—	(116)
Acquisition of Jefferson Island Storage & Hub, LLC	—	—	(90)
Sale of US Propane LP	—	—	31
Other	5	7	17
Net cash flow used in investing activities	(248)	(194)	(422)
Cash flows from financing activities			
Payments of trust preferred securities	(150)	—	—
Dividends paid on common shares	(111)	(100)	(75)
Purchase of treasury shares	(38)	—	—
Distribution to minority interest	(22)	(19)	(14)
Issuances of senior notes	175	—	450
Issuance of treasury shares	14	—	—
Net payments and borrowings of short-term debt	6	188	(480)
Sale of common stock	3	28	36
Equity offering	—	—	332
Payments of medium-term notes	—	—	(82)
Other	5	—	—
Net cash flow (used in) provided by financing activities	(118)	97	167
Net (decrease) increase in cash and cash equivalents	(12)	(17)	32
Cash and cash equivalents at beginning of period	32	49	17
Cash and cash equivalents at end of period	$ 20	$ 32	$ 49
Cash paid during the period for			
Interest (net of allowance for funds used during construction of $3 for the year ended December 31, 2006 and $2 for the years ended December 31, 2005 and 2004, respectively)	$ 108	$ 89	$ 50
Income taxes	37	89	27

See Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

Note 1 » Accounting Policies and Methods of Application

General

AGL Resources Inc. is an energy services holding company that conducts substantially all its operations through its subsidiaries. Unless the context requires otherwise, references to "we," "us," "our," the "company" or "AGL Resources" mean consolidated AGL Resources Inc. and its subsidiaries. We have prepared the accompanying consolidated financial statements under the rules of the Securities and Exchange Commission (SEC). For a glossary of key terms and referenced accounting standards, see pages 19–20.

Basis of Presentation

Our consolidated financial statements as of and for the period ended December 31, 2006 include our accounts, the accounts of our majority-owned and controlled subsidiaries and the accounts of variable interest entities for which we are the primary beneficiary. This means that our accounts are combined with the subsidiaries' accounts. We have eliminated any intercompany profits and transactions in consolidation; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process. Certain amounts from prior periods have been reclassified and revised to conform to the current-period presentation.

We currently own a noncontrolling 70% financial interest in SouthStar Energy Services, LLC (SouthStar), and Piedmont Natural Gas Company (Piedmont) owns the remaining 30%. Our 70% interest is noncontrolling because all significant management decisions require approval by both owners. Earnings related to customers in Ohio and Florida are allocated 70% to us and 30% to Piedmont. We record the earnings allocated to Piedmont as a minority interest in our consolidated statements of income and we record Piedmont's portion of SouthStar's capital as a minority interest in our consolidated balance sheets.

We are the primary beneficiary of SouthStar's activities and have determined that SouthStar is a variable interest entity as defined by Financial Accounting Standards Board (FASB) Interpretation No. 46, "Consolidation of Variable Interest Entities," as revised in December 2003 (FIN 46R). We determined that SouthStar was a variable interest entity because our equal voting rights with Piedmont are not proportional to our economic obligation to absorb 75% of any losses or residual returns from SouthStar, except those losses and returns related to customers in Ohio and Florida. In addition, SouthStar obtains substantially all its transportation capacity for delivery of natural gas through our wholly owned subsidiary, Atlanta Gas Light Company (Atlanta Gas Light).

Prior to our sale of Saltville Gas Storage Company, LLC (Saltville) in August 2005, we used the equity method to account for and report our 50% interest in Saltville. Saltville was a joint venture with a subsidiary of Duke Energy Corporation to develop a high-deliverability natural gas storage facility in Saltville, Virginia. We used the equity method because we exercised significant influence over but did not control the entity and because we were not the primary beneficiary as defined by FIN 46R.

Cash and Cash Equivalents

Our cash and cash equivalents consist primarily of cash on deposit, money market accounts and certificates of deposit with original maturities of three months or less.

Receivables and Allowance for Uncollectible Accounts

Our receivables consist of natural gas sales and transportation services billed to residential, commercial, industrial and other customers. We bill customers monthly, and accounts receivable are due within 30 days. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collection experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances that could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. We write off accounts once we deem them to be uncollectible.

Inventories

For our distribution operations subsidiaries, we record natural gas stored underground at weighted average costs. For Sequent Energy Management, L.P. (Sequent), SouthStar and Jefferson Island Storage & Hub, LLC (Jefferson Island), we account for natural gas inventory at the lower of weighted average cost or market.

Sequent and SouthStar evaluate the average cost of their natural gas inventories against market prices to determine whether

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any declines in market prices below the average cost are other than temporary. For any declines considered to be other than temporary, adjustments are recorded to reduce the weighted average cost of the natural gas inventory to market. Consequently, as a result of declining natural gas prices, Sequent recorded adjustments of $43 million and SouthStar recorded adjustments of $6 million in 2006 against cost of sales to reduce the value of their inventories to market value. Sequent recorded a $3 million adjustment in 2005 and a $1 million adjustment in 2004. SouthStar was not required to make similar adjustments in 2005 or in 2004.

For volumes of gas stored by Sequent under park and loan arrangements that are payable or to be repaid at predetermined dates to third parties, Sequent records the inventory at fair value. Materials and supplies inventories are stated at the lower of average cost or market.

In Georgia's competitive environment, Marketers—that is, marketers who are certificated by the Georgia Public Service Commission (Georgia Commission) to sell retail natural gas in Georgia, including SouthStar, our marketing subsidiary—began selling natural gas in 1998 to firm end-use customers at market-based prices. Part of the unbundling process, which resulted from deregulation that provides for this competitive environment, is the assignment to Marketers of certain pipeline services that Atlanta Gas Light has under contract. Atlanta Gas Light assigns, on a monthly basis, the majority of the pipeline storage services that it has under contract to Marketers, along with a corresponding amount of inventory.

Property, Plant and Equipment

A summary of our property, plant and equipment (PP&E) by classification as of December 31, 2006 and 2005 is provided in the following table.

In millions	2006	2005
Transmission and distribution	$ 4,047	$ 3.867
Storage	267	209
Other	454	476
Construction work in progress	208	239
Total gross PP&E	4,976	4,791
Accumulated depreciation	(1,540)	(1,458)
Total net PP&E	$ 3,436	$ 3,333

Distribution Operations » PP&E expenditures consist of property and equipment that is in use, being held for future use and under construction. We report PP&E at its original cost, which includes:

- material and labor
- contractor costs
- construction overhead costs
- an allowance for funds used during construction (AFUDC) which represents the estimated cost of funds used to finance the construction of major projects and is capitalized in the rate base for ratemaking purposes when the completed projects are placed in service

We charge property retired or otherwise disposed of to accumulated depreciation since such costs are recovered in rates.

Retail Energy Operations, Wholesale Services, Energy Investments and Corporate » PP&E expenditures include property that is in use and under construction, and we report it at cost. We record a gain or loss for retired or otherwise disposed-of property. These include such things as telecommunications conduit, fiber optic cable and other telecommunications equipment and tools.

Depreciation Expense

We compute depreciation expense for distribution operations by applying composite, straight-line rates (approved by the state regulatory agencies) to the investment in depreciable property. The composite straight-line depreciation rate for depreciable property—excluding transportation equipment for Atlanta Gas Light, Virginia Natural Gas, Inc. (Virginia Natural Gas) and Chattanooga Gas Company (Chattanooga Gas)—was approximately 2.5% during 2006, 2.6% during 2005 and 2.6% during 2004. The composite, straight-line rate for Elizabethtown Gas, Florida City Gas and Elkton Gas was approximately 3.0% for 2006, 3.1% during 2005 and 3.25% for December 2004. We depreciate transportation equipment on a straight-line basis over a period of 5 to 10 years. We compute depreciation expense for other segments on a straight-line basis over a period of 1 to 35 years.

AFUDC

The applicable state regulatory agencies authorize Atlanta Gas Light, Elizabethtown Gas and Chattanooga Gas to record the cost of debt and equity funds as part of the cost of construction projects in our consolidated balance sheets and as AFUDC in the statements of consolidated income. The Georgia Commission has authorized a rate of 8.53%, and the Tennessee Regulatory Authority (Tennessee Commission) has authorized a rate of

7.43%. Effective January 1, 2007, the Tennessee Commission authorized a rate of 7.89%. The New Jersey Board of Public Utilities (New Jersey Commission) has authorized a variable rate based on the Federal Energy Regulatory Commission (FERC) method of accounting for AFUDC. At December 31, 2006 the rate was 5.37%. The total AFUDC for the years ended December 31, 2006, 2005 and 2004 was $5 million, $4 million and $5 million, respectively. The capital expenditures of our other regulated utilities do not qualify for AFUDC treatment.

Goodwill

Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets" (SFAS 142), requires us to perform an annual goodwill impairment test. We have included $420 million of goodwill in our consolidated balance sheets as of December 31, 2006, of which $229 million is related to our acquisition of NUI Corporation (NUI) in November 2004; $170 million is related to our acquisition of Virginia Natural Gas in 2000; $14 million is related to our acquisition of Jefferson Island in October 2004; and $7 million is related to our acquisition of Chattanooga Gas in 1988.

We annually assess goodwill for impairment at a reporting unit level which generally equates to our operating segments as discussed in Note 11 "Segment Information," and have not recognized any impairment charges for the years ended December 31, 2006, 2005 and 2004. We also assess goodwill for impairment if events or changes in circumstances may indicate an impairment of goodwill exists. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, we record an impairment loss equal to the excess of the asset's carrying value over its fair value. We conduct this assessment principally through a review of financial results, changes in state and federal legislation and regulation, regulatory and legal proceedings and the periodic regulatory filings for our regulated utilities.

Taxes

Income Taxes » The reporting of our assets and liabilities for financial accounting purposes differs from the reporting for income tax purposes. The principal differences between net income and taxable income relate to the timing of deductions, primarily due to the benefits of tax depreciation since we generally depreciate assets for tax purposes over a shorter period of time than for book purposes. The determination of our provision for income taxes requires significant judgment, the use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. We report the tax effects of depreciation and other differences in those items as deferred income tax assets or liabilities in our consolidated balance sheets in accordance with SFAS No. 109, "Accounting for Income Taxes" (SFAS 109). Investment tax credits of approximately $18 million previously deducted for income tax purposes for Atlanta Gas Light, Elizabethtown Gas, Florida City Gas and Elkton Gas have been deferred for financial accounting purposes and are being amortized as credits to income over the estimated lives of the related properties in accordance with regulatory requirements.

State and Local Taxes » We collect and remit various taxes on behalf of various governmental authorities. We record these amounts in our consolidated balance sheets except taxes in the state of Florida which we are required to include in revenues and operating expenses. These Florida related taxes are not material for any periods presented.

Revenues

Distribution Operations » We record revenues when services are provided to customers. Those revenues are based on rates approved by the state regulatory commissions of our utilities.

As required by the Georgia Commission, in July 1998, Atlanta Gas Light began billing Marketers in equal monthly installments for each residential, commercial and industrial customer's distribution costs. As required by the Georgia Commission, effective February 1, 2001, Atlanta Gas Light implemented a seasonal rate design for the calculation of each residential customer's annual straight-fixed-variable (SFV) capacity charge, which is billed to Marketers and reflects the historic volumetric usage pattern for the entire residential class. Generally, this change results in residential customers being billed by Marketers for a higher capacity charge in the winter months and a lower charge in the summer months. This requirement has an operating cash flow impact but does not change revenue recognition. As a result, Atlanta Gas Light continues to recognize its residential SFV capacity revenues for financial reporting purposes in equal monthly installments.

Any difference between the billings under the seasonal rate design and the SFV revenue recognized is deferred and reconciled to actual billings on an annual basis. Atlanta Gas Light had unrecovered seasonal rates of approximately $11 million as of

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December 31, 2006 and $11 million as of December 31, 2005 (included as current assets in the consolidated balance sheets) related to the difference between the billings under the seasonal rate design and the SFV revenue recognized.

The Elizabethtown Gas, Virginia Natural Gas, Florida City Gas, Chattanooga Gas and Elkton Gas rate structures include volumetric rate designs that allow recovery of costs through gas usage. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. In addition, revenues are recorded for estimated deliveries of gas, not yet billed to these customers, from the meter reading date to the end of the accounting period. These are included in the consolidated balance sheets as unbilled revenue. For other commercial and industrial customers and all wholesale customers, revenues are based on actual deliveries to the end of the period.

The tariffs for Elizabethtown Gas, Virginia Natural Gas and Chattanooga Gas contain weather normalization adjustments (WNA) that largely mitigate the impact of unusually cold or warm weather on customer billings and operating margin. The WNA's purpose is to reduce the effect of weather on customer bills by reducing bills when winter weather is colder than normal and increasing bills when weather is warmer than normal.

Retail Energy Operations » We record retail energy operations' revenues when services are provided to customers. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Sales revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. In addition, revenues are recorded for estimated deliveries of gas, not yet billed to these customers, from the most recent meter reading date to the end of the accounting period. These are included in the consolidated balance sheets as unbilled revenue. For other commercial and industrial customers and all wholesale customers, revenues are based on actual deliveries to the end of the period.

Wholesale Services » We record wholesale services' revenues when services are provided to customers. Profits from sales between segments are eliminated in the corporate segment and are recognized as goods or services sold to end-use customers. Transactions that qualify as derivatives under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133), are recorded at fair value with changes in fair value recognized in earnings in the period of change and characterized as unrealized gains or losses.

Cost of Gas

Excluding Atlanta Gas Light, we charge our utility customers for natural gas consumed using purchased gas adjustment (PGA) mechanisms set by the state regulatory agencies. Under the PGA, we defer (that is, include as a current asset or liability in the consolidated balance sheets and exclude from the statements of consolidated income) the difference between the actual cost of gas and what is collected from or billed to customers in a given period. The deferred amount is either billed or refunded to our customers prospectively through adjustments to the commodity rate.

Our retail energy operations customers are charged for natural gas consumed. We also include within our cost of gas amounts for fuel and lost and unaccounted-for gas, adjustments to reduce the value of our inventories to market value and for gains and losses associated with derivatives.

Comprehensive Income

Our comprehensive income includes net income plus other comprehensive income (OCI), which includes other gains and losses affecting shareholders' equity that accounting principles generally accepted in the United States of America (GAAP) excludes from net income. Such items consist primarily of unrealized gains and losses on certain derivatives designated as cash flow hedges and minimum pension liability adjustments. The following table illustrates our OCI activity for the years ended December 31, 2006, 2005 and 2004.

In millions	2006	2005	2004
Cash flow hedges:			
Net derivative unrealized gains arising during the period (net of $7, $3 and $3 in taxes)	$11	$ 5	$ 6
Less reclassification of realized gains included in income (net of $1, $4 and $1 in taxes)	(1)	(7)	(2)
Overfunded (unfunded) pension obligation (net of $7, $3 and $7 in taxes)	11	(5)	(11)
Other (net of tax)	—	—	1
Total	$21	$ (7)	$ (6)

Earnings Per Common Share

We compute basic earnings per common share by dividing our income available to common shareholders by the daily weighted average number of common shares outstanding. Diluted earnings per common share reflect the potential reduction in earnings per common share that could occur when potentially dilutive common shares are added to common shares outstanding.

We derive our potentially dilutive common shares by calculating the number of shares issuable under performance units and stock options. The future issuance of shares underlying the performance units depends on the satisfaction of certain performance criteria. The future issuance of shares underlying the outstanding stock options depends on whether the exercise prices of the stock options are less than the average market price of the common shares for the respective periods. No items are antidilutive. The following table shows the calculation of our diluted earnings per share for the periods presented if performance units currently earned under the plan ultimately vest and if stock options currently exercisable at prices below the average market prices are exercised.

In millions	2006	2005	2004
Denominator for basic earnings per share[1]	**77.6**	77.3	66.3
Assumed exercise of potential common shares	**0.4**	0.5	0.7
Denominator for diluted earnings per share	**78.0**	77.8	67.0

[1] Daily weighted average shares outstanding.

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, and we evaluate our estimates on an ongoing basis. Each of our estimates involve complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. The most significant estimates include our regulatory accounting, pipeline replacement program (PRP) accruals, environmental liability accruals, derivative and hedging activities, allowance for contingencies, pension and postretirement obligations and provision for income taxes. Our actual results could differ from our estimates.

Accounting Developments

FIN 48 » In July 2006, the FASB issued SFAS Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of SFAS Statement No. 109" (FIN 48). FIN 48 applies to all "tax positions" accounted for under SFAS 109. FIN 48 refers to "tax positions" as positions taken in a previously filed tax return or positions expected to be taken in a future tax return that are reflected in measuring current or deferred income tax assets and liabilities reported in the financial statements. FIN 48 further clarifies a tax position to include the following:

- a decision not to file a tax return in a particular jurisdiction for which a return might be required,
- an allocation or a shift of income between taxing jurisdictions,
- the characterization of income or a decision to exclude reporting taxable income in a tax return, or
- a decision to classify a transaction, entity, or other position in a tax return as tax exempt.

FIN 48 clarifies that a tax benefit may be reflected in the financial statements only if it is "more likely than not" that a company will be able to sustain the tax return position, based on its technical merits. If a tax benefit meets this criterion, it should be measured and recognized based on the largest amount of benefit that is cumulatively greater than 50% likely to be realized. This is a change from current practice, whereby companies may recognize a tax benefit only if it is probable a tax position will be sustained.

FIN 48 also requires that we make qualitative and quantitative disclosures, including a discussion of reasonably possible changes that might occur in unrecognized tax benefits over the next 12 months; a description of open tax years by major jurisdictions; and a roll-forward of all unrecognized tax benefits, presented as a reconciliation of the beginning and ending balances of the unrecognized tax benefits on an aggregated basis.

This statement became effective for us on January 1, 2007 and, based on our analysis, FIN 48 does not have a material effect on our consolidated results of operations, cash flows or financial position.

SFAS 157 » In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS 157). SFAS 157 establishes a framework for measuring fair value and requires expanded disclosures regarding fair value measurements. SFAS 157 does not

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require any new fair value measurements. However, it eliminates inconsistencies in the guidance provided in previous accounting pronouncements.

SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including financial statements for an interim period within that fiscal year. All valuation adjustments will be recognized as cumulative-effect adjustments to the opening balance of retained earnings for the fiscal year in which SFAS 157 is initially applied. We are currently evaluating the impact that SFAS 157 will have on our consolidated results of operations, cash flows and financial position.

Note 2 » Risk Management

Our risk management activities are monitored by our Risk Management Committee (RMC). The RMC consists of members of senior management and is charged with reviewing and enforcing our risk management activities. Our risk management policies limit the use of derivative financial instruments and physical transactions within predefined risk tolerances associated with pre-existing or anticipated physical natural gas sales and purchases and system use and storage. We use the following derivative financial instruments and physical transactions to manage commodity price, interest rate and weather risks:

- forward contracts
- futures contracts
- options contracts
- financial swaps
- treasury locks
- weather derivative contracts
- storage and transportation capacity transactions

Interest Rate Swaps

To maintain an effective capital structure, our policy is to borrow funds using a mix of fixed-rate and variable-rate debt. We entered into interest rate swap agreements for the purpose of managing the interest rate risk associated with our fixed-rate and variable-rate debt obligations. We designated these interest rate swaps as fair value hedges in accordance with SFAS 133. We record the gain or loss on fair value hedges in earnings in the period of change, together with the offsetting loss or gain on the hedged item attributable to the risk being hedged.

As of December 31, 2006, a notional principal amount of $100 million of these interest rate swap agreements effectively converted the interest expense associated with a portion of our senior notes from fixed rates to variable rates based on an interest rate equal to the London Interbank Offered Rate (LIBOR), plus a spread determined at the swap date. The floating rate for our interest rate swaps for the year ended December 31, 2006, was 9.0%.

Commodity-related Derivative Instruments

Elizabethtown Gas » In accordance with a directive from the New Jersey Commission, Elizabethtown Gas enters into derivative transactions to hedge the impact of market fluctuations in natural gas prices. Pursuant to SFAS 133, such derivative transactions are marked to market each reporting period. In accordance with regulatory requirements, realized gains and losses related to these derivatives are reflected in purchased gas costs and ultimately included in billings to customers. As of December 31, 2006, Elizabethtown Gas had entered into New York Mercantile Exchange (NYMEX) futures contracts to purchase approximately 8.55 Bcf of natural gas. Approximately 81% of these contracts have a duration of one year or less, and none of these contracts extends beyond October 2008.

Sequent » We are exposed to risks associated with changes in the market price of natural gas. Sequent uses derivative financial instruments to reduce our exposure to the risk of changes in the prices of natural gas. The fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all the financial instruments we use.

We mitigate substantially all the commodity price risk associated with Sequent's natural gas portfolio by locking in the economic margin at the time we enter into natural gas purchase transactions for our stored natural gas. We purchase natural gas for storage when the difference in the current market price we pay to buy and transport natural gas plus the cost to store the natural gas is less than the market price we can receive in the future, resulting in a positive net profit margin. We use NYMEX futures contracts and other over-the-counter derivatives to sell natural gas at that future price to substantially lock in the profit margin we will ultimately realize when the stored gas is actually sold. These futures contracts meet the definition of derivatives under SFAS 133 and are recorded at fair value and marked to market in our consolidated balance sheets, with changes in fair value recorded in earnings in the period of change. The purchase, transportation, storage and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate rather than on the mark-to-market basis we utilize for the derivatives used to mitigate the commodity price risk associated with our storage portfolio. This difference in accounting can result in volatility in our reported earnings, even though the economic margin is essentially unchanged from the date the transactions were consummated.

At December 31, 2006, Sequent's commodity-related derivative financial instruments represented purchases (long) of 607 Bcf and sales (short) of 614 Bcf with approximately 94% of these instruments scheduled to mature in less than two years and the remaining 6% in three to nine years. At December 31, 2006, the fair values of these derivatives were reflected in our consolidated financial statements as an asset of $133 million and a liability of $14 million. Sequent recorded a net unrealized gain related to changes in the fair value of derivative instruments utilized in its energy marketing and risk management activities of $132 million during 2006, $30 million of unrealized losses during 2005 and unrealized gains of $22 million during 2004.

SouthStar » Commodity-related derivative financial instruments (futures, options and swaps) are used by SouthStar to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to utilize the most effective method to reduce or eliminate the impact of this exposure. We have designated a portion of SouthStar's derivative transactions as cash flow hedges under SFAS 133. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period as the settlement of the underlying hedged item. We record any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not offset and are greater than the losses or gains on the hedged item, in cost of gas in our statement of consolidated income in the period in which it occurs. SouthStar currently has minimal hedge ineffectiveness. We have not designated the remainder of SouthStar's derivative instruments as hedges under SFAS 133 and, accordingly, we record changes in their fair value in earnings in the period of change.

At December 31, 2006, the fair values of these derivatives were reflected in our consolidated financial statements as a current asset of $28 million and a current liability of $12 million. For those open derivatives with maturity dates beyond December 31, 2007, the fair value of these derivatives is reflected as a long-term asset of $2 million in our consolidated financial statements. The maximum maturity of open positions is less than two years, with those positions greater than one year but less than two years representing a net position of 0.2 Bcf.

SouthStar also enters into both exchange and over-the-counter derivative transactions to hedge commodity price risk. Credit risk is mitigated for exchange transactions through the backing of the NYMEX member firms. For over-the-counter transactions, SouthStar utilizes master netting arrangements to reduce overall credit risk. As of December 31, 2006, SouthStar's maximum exposure to any single over-the-counter counterparty was $7 million.

Weather Derivatives

In September 2006, SouthStar entered into weather derivative contracts as an economic hedge of operating margins in the event of warmer-than-normal weather in the current heating season, primarily from November 2006 through March 2007. SouthStar accounts for these contracts using the intrinsic value method under the guidelines of Emerging Issues Task Force Issue No. 99-02, "Accounting for Weather Derivatives." SouthStar had no weather derivatives outstanding as of December 31, 2005 or 2004. As of December 31, 2006, SouthStar recorded a receivable of $7 million for this hedging activity.

Concentration of Credit Risk

Atlanta Gas Light » Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 11 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the nonpeak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of natural gas. Atlanta Gas Light's tariff allows it to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light.

Wholesale Services » Sequent has a concentration of credit risk for services it provides to marketers and to utility and industrial customers. This credit risk is measured by 30-day receivable exposure plus forward exposure, which is generally concentrated in 20 of its customers. Sequent evaluates the credit risk of its customers using a Standard & Poor's Ratings Services (S&P) equivalent credit rating, which is determined by a process of converting the lower of the S&P or Moody's Investors Service (Moody's) rating

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to an internal rating ranging from 9.00 to 1.00, with 9.00 being equivalent to AAA/Aaa by S&P and Moody's and 1.00 being equivalent to D or Default by S&P and Moody's. For a customer without an external rating, Sequent assigns an internal rating based on Sequent's analysis of the strength of its financial ratios. At December 31, 2006, Sequent's top 20 customers represented approximately 57% of the total credit exposure of $394 million, derived by adding together the top 20 customers' exposures and dividing by the total of Sequent's counterparties' exposures. Sequent's customers or the customers' guarantors had a weighted average S&P equivalent rating of A- at December 31, 2006.

The weighted average credit rating is obtained by multiplying each customer's assigned internal rating by its credit exposure and then adding the individual results for all counterparties. That total is divided by the aggregate total exposure. This numeric value is converted to an S&P equivalent.

Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, including requirements for posting of collateral or other credit security, as well as the quality of pledged collateral. Collateral or credit security is most often in the form of cash or letters of credit from an investment-grade financial institution, but may also include cash or U.S. Government Securities held by a trustee. When Sequent is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of Sequent's credit risk. Sequent also uses other netting agreements with certain counterparties with which it conducts significant transactions.

All activities associated with price risk management activities and derivative instruments are included as a component of cash flows from operating activities in our consolidated statements of cash flows. Our derivatives not designated as hedges under SFAS 133, included in operating cash flows for the years ended December 31, 2006, 2005, and 2004 were $(128) million, $36 million, and $(22) million, respectively.

Note 3 » Regulatory Assets and Liabilities

We have recorded regulatory assets and liabilities in our consolidated balance sheets in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). Our regulatory assets and liabilities, and associated liabilities for our unrecovered PRP costs, unrecovered environmental remediation costs (ERC) and the associated assets and liabilities for our Elizabethtown Gas hedging program, are summarized in the table below.

In millions	December 31, 2006	2005
Regulatory assets		
Unrecovered PRP costs	$274	$303
Unrecovered ERC	170	196
Elizabethtown Gas hedging program	16	—
Unrecovered postretirement benefit costs	13	14
Unrecovered seasonal rates	11	11
Unrecovered PGA	14	8
Other	13	10
Total regulatory assets	511	542
Associated assets		
Elizabethtown Gas hedging program	—	17
Total regulatory and associated assets	$511	$559
Regulatory liabilities		
Accumulated removal costs	$162	$156
Elizabethtown Gas hedging program	—	17
Unamortized investment tax credit	18	19
Deferred PGA	24	40
Regulatory tax liability	22	17
Other	10	6
Total regulatory liabilities	236	255
Associated liabilities		
PRP costs	237	265
ERC	87	88
Elizabethtown Gas hedging program	16	—
Total associated liabilities	340	353
Total regulatory and associated liabilities	$576	$608

Our regulatory assets are recoverable through either rate riders or base rates specifically authorized by a state regulatory commission. Base rates are designed to provide both a recovery of cost and a return on investment during the period rates are in effect. As such, all our regulatory assets are subject to review by the respective state regulatory commission during any future rate proceedings. In the event that the provisions of SFAS 71 were no longer applicable, we would recognize a write-off of net regulatory assets (regulatory assets less regulatory liabilities) that would result in a charge to net income, and classified as an extraordinary item. Although the natural gas distribution industry is becoming increasingly competitive, our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under SFAS 71 remains appropriate. It is also our opinion that all regulatory assets are recoverable in future rate proceedings, and therefore we have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a rate rider.

All the regulatory assets included in the table above are included in base rates except for the unrecovered PRP costs, unrecovered ERC and the deferred PGA, which are recovered through specific rate riders on a dollar for dollar basis. The rate riders that authorize recovery of unrecovered PRP costs and the deferred PGA include both a recovery of costs and a return on investment during the recovery period. We have two rate riders that authorize the recovery of unrecovered ERC. The ERC rate rider for Atlanta Gas Light only allows for recovery of the costs incurred and the recovery period occurs over the five years after the expense is incurred. ERC associated with the investigation and remediation of Elizabethtown Gas remediation sites located in the state of New Jersey are recovered under a remediation adjustment clause and include the carrying cost on unrecovered amounts not currently in rates. Elizabethtown Gas's hedging program asset reflects unrealized losses that will be recovered through the PGA on a dollar for dollar basis, once the losses are realized. Unrecovered postretirement benefit costs are recoverable through base rates over the next 7 to 26 years based on the remaining recovery period as designated by the applicable state regulatory commissions. Unrecovered seasonal rates reflect the difference between the recognition of a portion of Atlanta Gas Light's residential base rates revenues on a straight-line basis as compared to the collection of the revenues over a seasonal pattern. The unrecovered amounts are fully recoverable through base rates within one year.

The regulatory liabilities are refunded to ratepayers through a rate rider or base rates. If the regulatory liability is included in base rates, the amount is reflected as a reduction to the rate base in setting rates.

Pipeline Replacement Program

Atlanta Gas Light » The PRP, ordered by the Georgia Commission to be administered by Atlanta Gas Light, requires, among other things, that Atlanta Gas Light replace all bare steel and cast iron pipe in its system in the state of Georgia within a 10-year period beginning October 1, 1998. Atlanta Gas Light identified, and provided notice to the Georgia Commission of 2,312 miles of pipe to be replaced. Atlanta Gas Light has subsequently identified an additional 320 miles of pipe subject to replacement under this program. If Atlanta Gas Light does not perform in accordance with this order, it will be assessed certain nonperformance penalties. October 1, 2006 marked the beginning of the ninth year of the 10-year PRP.

The order also provides for recovery of all prudent costs incurred in the performance of the program, which Atlanta Gas Light has recorded as a regulatory asset. Atlanta Gas Light will recover from end-use customers, through billings to Marketers, the costs related to the program net of any cost savings from the program. All such amounts will be recovered through a combination of straight-fixed-variable rates and a pipeline replacement revenue rider. The regulatory asset has two components:

- the costs incurred to date that have not yet been recovered through the rate rider
- the future expected costs to be recovered through the rate rider

On June 10, 2005, Atlanta Gas Light and the Georgia Commission entered into a Settlement Agreement that, among other things, extends Atlanta Gas Light's PRP by five years to require that all replacements be completed by December 2013. The timing of replacements was subsequently specified in an amendment to the PRP stipulation. This amendment, which was approved by the Georgia Commission on December 20, 2005, requires Atlanta Gas Light to replace all cast iron pipe and 70% of all bare steel pipe by December 2010. The remaining 30% of bare steel pipe is required to be replaced by December 2013.

Under the Settlement Agreement, base rates charged to customers will remain unchanged through April 30, 2010, but Atlanta Gas Light will recognize reduced base rate revenues of $5 million on an annual basis through April 30, 2010. The five-year total reduction in recognized base rate revenues of $25 million will be applied to the allowed amount of costs incurred to replace pipe, which will reduce the amounts recovered from customers under the PRP rider. The Settlement Agreement also set the per customer fixed PRP rate that Atlanta Gas Light will charge at $1.29 per customer per month from May 2005 through September 2008 and at $1.95 from October 2008 through December 2013 and includes a provision that allows for a true-up of any over- or under-recovery of PRP revenues that may result from a difference between PRP charges collected through fixed rates and actual PRP revenues recognized through the remainder of the program.

The Settlement Agreement also allows Atlanta Gas Light to recover through the PRP $4 million of the $32 million capital costs associated with its purchase of 250 miles of pipeline in central

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Georgia from Southern Natural Gas Company, a subsidiary of El Paso Corporation. The remaining capital costs are included in Atlanta Gas Light's rate base and collected through base rates.

Atlanta Gas Light has recorded a long-term regulatory asset of $247 million, which represents the expected future collection of both expenditures already incurred and expected future capital expenditures to be incurred through the remainder of the program. Atlanta Gas Light has also recorded a current asset of $27 million, which represents the expected amount to be collected from customers over the next 12 months. The amounts recovered from the pipeline replacement revenue rider during the last three years were:

- $27 million in 2006
- $26 million in 2005
- $28 million in 2004

As of December 31, 2006, Atlanta Gas Light had recorded a current liability of $35 million, representing expected program expenditures for the next 12 months and a long-term liability of $202 million, representing expected program expenditures starting in 2008 through the end of the program in 2013.

Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the PRP over the life of the assets. Operation and maintenance costs are expensed as incurred. Recoveries, which are recorded as revenue, are based on a formula that allows Atlanta Gas Light to recover operation and maintenance costs in excess of those included in its current base rates, depreciation expense and an allowed rate of return on capital expenditures. In the near term, the primary financial impact to Atlanta Gas Light from the PRP is reduced cash flow from operating and investing activities, as the timing related to cost recovery does not match the timing of when costs are incurred. However, Atlanta Gas Light is allowed the recovery of carrying costs on the under-recovered balance resulting from the timing difference.

Elizabethtown Gas » In August 2006, the New Jersey Commission issued an order adopting a pipeline replacement cost recovery rider program for the replacement of certain 8″ cast iron main pipes and any unanticipated 10″–12″ cast iron main pipes integral to the replacement of the 8″ main pipes. The order allows Elizabethtown Gas to recognize revenues under a deferred recovery mechanism for costs to replace the pipe that exceeds a baseline amount of $3 million. The term of the stipulation is from the date of the order through December 31, 2008. Total replacement costs through December 31, 2008 are expected to be $10 million, of which $7 million will be eligible for the deferred recovery mechanism. Revenues recognized and deferred for recovery under the stipulation are estimated to be approximately $1 million. All costs incurred under the program will be included in Elizabethtown Gas' next rate case to be filed in 2009.

Environmental Remediation Costs

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites.

Atlanta Gas Light » The presence of coal tar and certain other byproducts of a natural gas manufacturing process used to produce natural gas prior to the 1950s has been identified at or near 10 former Atlanta Gas Light operating sites in Georgia and at 3 sites of predecessor companies in Florida. Atlanta Gas Light has active environmental remediation or monitoring programs in effect at 10 of these sites. Two sites in Florida are currently in the investigation or preliminary engineering design phase, and one Georgia site has been deemed compliant with state standards.

Atlanta Gas Light has customarily reported estimates of future remediation costs for these former sites based on probabilistic models of potential costs. These estimates are reported on an undiscounted basis. As cleanup options and plans mature and cleanup contracts are entered into, Atlanta Gas Light is better able to provide conventional engineering estimates of the likely costs of remediation at its former sites. These estimates contain various engineering uncertainties, but Atlanta Gas Light continuously attempts to refine and update these engineering estimates.

Atlanta Gas Light's current estimate for the remaining cost of future actions at its former operating sites is $27 million, a reduction of $4 million over 2005, which may change depending on whether future measures for groundwater will be required.

These liabilities do not include other potential expenses, such as unasserted property damage claims, personal injury or natural resource damage claims, unbudgeted legal expenses or other costs for which Atlanta Gas Light may be held liable but for which it cannot reasonably estimate an amount. As of December 31, 2006, the remediation expenditures expected to be incurred over the next 12 months are reflected as a current liability of $13 million.

The ERC liability is included as a corresponding regulatory asset, which is a combination of accrued ERC and unrecovered cash expenditures for investigation and cleanup costs. Atlanta Gas Light has three ways of recovering investigation and cleanup costs. First, the Georgia Commission has approved an ERC recovery rider. The ERC recovery mechanism allows for recovery of expenditures over a five-year period subsequent to the period in which the expenditures are incurred. Atlanta Gas Light expects to collect $26 million in revenues over the next 12 months under the ERC recovery rider, which is reflected as a current asset. The amounts recovered from the ERC recovery rider during the last three years were:

- $29 million in 2006
- $28 million in 2005
- $25 million in 2004

The second way to recover costs is by exercising the legal rights Atlanta Gas Light believes it has to recover a share of its costs from other potentially responsible parties, typically former owners or operators of these sites. There were no material recoveries from potentially responsible parties during 2006, 2005 or 2004.

The third way to recover costs is from the receipt of net profits from the sale of remediated property. There was one sale of property during 2006.

Elizabethtown Gas » In New Jersey, Elizabethtown Gas is currently conducting remediation activities with oversight from the New Jersey Department of Environmental Protection. Although we cannot estimate the actual total cost of future environmental investigation and remediation efforts with precision, based on probabilistic models similar to those used at Atlanta Gas Light's former operating sites, the range of reasonably probable costs is $60 million to $118 million. As of December 31, 2006, we have recorded a liability equal to the low end of that range, or $60 million, of which $6 million in expenditures are expected to be incurred over the next 12 months.

Prudently incurred remediation costs for the New Jersey properties have been authorized by the New Jersey Commission to be recoverable in rates through a remediation adjustment clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $65 million, inclusive of interest, as of December 31, 2006, reflecting the future recovery of both incurred costs and accrued carrying charges. Elizabethtown Gas expects to collect $1 million in revenues over the next 12 months. Elizabethtown Gas has also been successful in recovering a portion of remediation costs incurred in New Jersey from its insurance carriers and continues to pursue additional recovery.

Note 4 » Employee Benefit Plans

Pension Benefits

We sponsor two tax-qualified defined benefit retirement plans for our eligible employees, the AGL Resources Inc. Retirement Plan (AGL Retirement Plan) and the Employees' Retirement Plan of NUI Corporation (NUI Retirement Plan). A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant.

We generally calculate the benefits under the AGL Retirement Plan based on age, years of service and pay. The benefit formula for the AGL Retirement Plan is a career average earnings formula, except for participants who were employees as of July 1, 2000, and who were at least 50 years of age as of that date. For those participants, we use a final average earnings benefit formula, and will continue to use this benefit formula for such participants until June 2010, at which time any of those participants who are still active will accrue future benefits under the career average earnings formula.

The NUI Retirement Plan covers substantially all of NUI's employees who were employed on or before December 31, 2005, except Florida City Gas union employees, who participate in a union-sponsored multiemployer plan. Pension benefits are based on years of credited service and final average compensation.

Effective with our acquisition of NUI in November 2004, we became sponsor of the NUI Retirement Plan. Throughout 2005, we maintained existing benefits for NUI employees, including participation in the NUI Retirement Plan. Beginning in 2006, eligible participants in the NUI Retirement Plan became eligible to participate in the AGL Retirement Plan and the benefits of those participants under the NUI Retirement Plan were frozen as of December 31, 2005, resulting in a $15 million reduction to the NUI Retirement Plan's projected benefit obligation as of December 31, 2005. Participants in the NUI Retirement Plan have the option of receiving a lump sum distribution upon retirement for all benefits earned through December 31, 2005. This resulted in settlement payments of $12 million and an immaterial settlement loss. This option is not permitted under the AGL Retirement Plan, except for accrued benefits valued at less than $10,000.

SFAS 158 » In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS 158). We adopted SFAS 158 prospectively on December 31, 2006. SFAS 158 requires that we recognize all obligations related to defined benefit pensions and

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other postretirement benefits. This statement requires that we quantify the plans' funding status as an asset or a liability in our consolidated balance sheets.

SFAS 158 requires that we measure the plans' assets and obligations that determine our funded status as of the end of the fiscal year. We are also required to recognize as a component of OCI the changes in funded status that occurred during the year that are not recognized as part of net periodic benefit cost as explained in SFAS No. 87, "Employers' Accounting for Pensions," or SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions."

Based on the funded status of our defined benefit pension and postretirement benefit plans as of December 31, 2006, we reported a gain to our OCI of $11 million, a decrease of $18 million to accrued pension obligations and an increase of $7 million to accumulated deferred income taxes. Our adoption of SFAS 158 on December 31, 2006, had no impact on our earnings. The following tables present details about our pension plans.

	AGL Retirement Plan		NUI Retirement Plan	
In millions	**Dec. 31, 2006**	Dec. 31, 2005	**Dec. 31, 2006**	Dec. 31, 2005
Change in benefit obligation				
Benefit obligation at beginning of year	**$359**	$340	**$105**	$144
Service cost	**7**	6	**—**	4
Interest cost	**20**	19	**5**	8
Plan amendments	**—**	—	**—**	(15)
Settlement loss	**—**	—	**1**	—
Settlement payments	**—**	—	**(12)**	—
Actuarial loss (gain)	**2**	14	**(7)**	(4)
Benefits paid	**(20)**	(20)	**(6)**	(32)
Benefit obligation at end of year	**$368**	$359	**$ 86**	$105
Change in plan assets				
Fair value of plan assets at beginning of year	**$286**	$279	**$ 85**	$111
Actual return on plan assets	**31**	21	**4**	6
Employer contribution	**6**	6	**1**	—
Settlement payments	**—**	—	**(12)**	—
Benefits paid	**(20)**	(20)	**(6)**	(32)
Fair value of plan assets at end of year	**$303**	$286	**$ 72**	$ 85
Reconciliation of funded status[1]				
Plan assets less than benefit obligation at end of year	**$ (65)**	$ (73)	**$ (14)**	$ (20)
Unrecognized net loss	**—**	119	**—**	4
Unrecognized prior service benefit	**—**	(10)	**—**	(15)
(Prepaid) accrued pension cost[2]	**$ (65)**	$ 36	**$ (14)**	$ (31)
Amounts recognized in the statement of financial position consist of				
Prepaid benefit cost	**$ —**	$ 42	**$ —**	$ —
Accrued benefit liability	**(65)**	(7)	**(14)**	(31)
Accumulated OCI	**—**	(92)	**—**	—
Net amount recognized at year end[3]	**$ (65)**	$ (57)	**$ (14)**	$ (31)

[1] After adoption of SFAS 158 on December 31, 2006, these amounts are recorded and this reconciliation is no longer required.

[2] The prepaid pension cost for the NUI Retirement Plan at December 31, 2005 was adjusted for termination and settlement of liabilities for participants affected by our acquisition of NUI in November 2004. In 2005, we recorded the associated $9 million reduction in our benefit obligation as a reduction to goodwill.

[3] As of December 31, 2006, the AGL Retirement Plan had current liabilities of $1 million, noncurrent liabilities of $64 million and no noncurrent assets. The NUI Retirement Plan had $14 million of noncurrent liabilities and no noncurrent assets or current liabilities.

The accumulated benefit obligation (ABO) and other information for the AGL Retirement Plan and the NUI Retirement Plan are set forth in the following table.

	AGL Retirement Plan		NUI Retirement Plan	
In millions	**Dec. 31, 2006**	Dec. 31, 2005	**Dec. 31, 2006**	Dec. 31, 2005
Projected benefit obligation	**$368**	$359	**$86**	$105
ABO	**352**	343	**86**	105
Fair value of plan assets	**303**	286	**72**	85
Increase in minimum liability included in OCI	**13**	8	**—**	—
Components of net periodic benefit cost				
Service cost	**$ 7**	$ 6	**$ —**	$ 4
Interest cost	**20**	19	**5**	8
Expected return on plan assets	**(24)**	(24)	**(7)**	(9)
Net amortization	**(1)**	(1)	**(1)**	—
Recognized actuarial loss	**9**	7	**—**	—
Net annual pension cost	**$ 11**	$ 7	**$ (3)**	$ 3

There were no other changes in plan assets and benefit obligations recognized for the AGL and NUI Retirement Plans for the year ended December 31, 2006.

The 2007 estimated OCI amortization and expected refunds for the AGL and NUI Retirement Plans are set forth in the following table.

	Retirement Plan	
In millions	AGL	NUI
Amortization of transition obligation	$—	$—
Amortization of prior service cost	(1)	(1)
Amortization of net loss	6	—
Refunds expected	—	—

The effects of SFAS 158, including the additional minimum liability (AML) adjustments, for the AGL Retirement Plan and the NUI Retirement Plan are set forth in the following table.

AGL Retirement Plan

In millions	Pre-SFAS 158 without AML adjustment	AML adjustment	Pre-SFAS 158 with AML adjustment	SFAS 158 adoption adjustments	Post-SFAS 158
Prepaid pension asset (accrued pension liability)	$30	$(79)	$(49)	$(16)	$(65)
Intangible asset	—	—	—	—	—
Deferred tax asset	—	30	30	6	36
OCI—pension, net of tax	—	49	49	10	59
OCI—pension, pre-tax	—	79	79	16	95

NUI Retirement Plan

In millions	Pre-SFAS 158 without AML adjustment[1]	AML adjustment[1]	Pre-SFAS 158 with AML adjustment[1]	SFAS 158 adoption adjustments	Post-SFAS 158
Prepaid pension asset (accrued pension liability)	$(27)	$—	$(27)	$ 13	$(14)
Intangible asset	—	—	—	—	—
Deferred tax asset	—	—	—	(5)	(5)
OCI—pension, net of tax	—	—	—	(8)	(8)
OCI—pension, pre-tax	—	—	—	(13)	(13)

[1] Values represent amounts less than $1 million.

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The following table sets forth the assumed weighted average discount rates and rates of compensation increase used to determine benefit obligations at December 31.

AGL and NUI Retirement Plans	2006	2005
Discount rate	5.8%	5.5%
Rate of compensation increase	4.0%	4.0%

We consider a number of factors in determining and selecting assumptions for the overall expected long-term rate of return on plan assets. We consider the historical long-term return experience of our assets, the current and expected allocation of our plan assets, and expected long-term rates of return. We derive these expected long-term rates of return with the assistance of our investment advisors and generally base these rates on a 10-year horizon for various asset classes, our expected investments of plan assets and active asset management as opposed to investment in a passive index fund. We base our expected allocation of plan assets on a diversified portfolio consisting of domestic and international equity securities, fixed income, real estate, private equity securities and alternative asset classes.

The following tables present the assumed weighted average discount rate, expected return on plan assets and rate of compensation increase used to determine net periodic benefit cost at the beginning of the period, which was January 1.

AGL Retirement Plan	2006	2005	2004
Discount rate	5.5%	5.8%	6.3%
Expected return on plan assets	8.8%	8.8%	8.8%
Rate of compensation increase	4.0%	4.0%	4.0%

NUI Retirement Plan	2006	2005	2004
Discount rate	5.5%	5.8%	5.8%
Expected return on plan assets	8.8%	8.5%	8.5%
Rate of compensation increase	—%	4.0%	4.0%

We consider a variety of factors in determining and selecting our assumptions for the discount rate at December 31. We consider certain market indices, including Moody's Corporate AA long-term bond rate, the Citigroup Pension Liability rate our actuaries model and our own payment stream based on these indices to develop our rate. Consequently, we selected a discount rate of 5.8% as of December 31, 2006, following our review of these various factors.

Our actual retirement plans' weighted average asset allocations at December 31, 2006 and 2005 and our target asset allocation ranges are as follows:

	Target range asset allocation	AGL Retirement Plan 2006	2005
Equity	30%–80%	67%	66%
Fixed income	10%–40%	25%	25%
Real estate and other	10%–35%	8%	8%
Cash	0%–10%	0%	1%

	Target range asset allocation	NUI Retirement Plan 2006	2005
Equity	30%–80%	68%	88%
Fixed income	10%–40%	26%	12%
Real estate and other	10%–35%	3%	—
Cash	0%–10%	3%	—

The Retirement Plan Investment Committee (the Committee) appointed by our Board of Directors is responsible for overseeing the investments of the retirement plans. Further, we have an Investment Policy (the Policy) for the retirement plans that aims to preserve the retirement plans' capital and maximize investment earnings in excess of inflation within acceptable levels of capital market volatility. To accomplish this goal, the retirement plans' assets are actively managed to optimize long-term return while maintaining a high standard of portfolio quality and proper diversification.

The Policy's risk management strategy establishes a maximum tolerance for risk in terms of volatility to be measured at 75% of the volatility experienced by the S&P 500. We will continue to diversify retirement plan investments to minimize the risk of large losses in a single asset class. The Policy's permissible investments include domestic and international equities (including convertible securities and mutual funds), domestic and international fixed income (corporate and U.S. government obligations), cash and cash equivalents and other suitable investments. The asset mix of these permissible investments is maintained within the Policy's target allocations as included in the preceding tables, but the Committee can vary allocations between various classes or investment managers in order to improve investment results.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded ABO, as the primary factors that drive the value of our unfunded ABO are the assumed discount rate and the actual return on plan assets. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes the difference between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year moving weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year moving weighted average methodology, which affects the expected return on plan assets component of pension expense.

Our employees do not contribute to the retirement plans. We fund the plans by contributing at least the minimum amount required by applicable regulations and as recommended by our actuary. However, we may also contribute in excess of the minimum required amount. We calculate the minimum amount of funding using the projected unit credit cost method. The Pension Protection Act (the Act) of 2006 contains new funding requirements for single-employer defined benefit pension plans. The Act establishes a 100% funding target for plan years beginning after December 31, 2007. However, a delayed effective date of 2011 may apply if the pension plan meets the following targets: 92% funded in 2008; 94% funded in 2009; and 96% funded in 2010. In October 2006 we made a voluntary contribution of $5 million to the AGL Resources Inc. Retirement Plan. No contribution is required for the qualified plans in 2007.

Postretirement Benefits

Until January 1, 2006, we sponsored two defined benefit postretirement health care plans for our eligible employees, the AGL Resources Inc. Postretirement Health Care Plan (AGL Postretirement Plan) and the NUI Corporation Postretirement Health Care Plan (NUI Postretirement Plan), which we acquired upon our acquisition of NUI. Eligibility for these benefits is based on age and years of service.

The NUI Postretirement Plan provided certain medical and dental health care benefits to retirees, other than retirees of Florida City Gas, depending on their age, years of service and start date. The NUI Postretirement Plan was contributory, and NUI funded a portion of these future benefits through a Voluntary Employees' Beneficiary Association. Effective July 2000, NUI no longer offered postretirement benefits other than pension for any new hires. In addition, NUI capped its share of costs at $500 per participant per month for retirees under age 65, and at $150 per participant per month for retirees over age 65. At the beginning of 2006, eligible participants in the NUI Postretirement Plan became eligible to participate in the AGL Postretirement Plan and all participation in this plan ceased, effective January 1, 2006.

The AGL Postretirement Plan covers all eligible AGL Resources employees who were employed as of June 30, 2002, if they reach retirement age while working for us. The state regulatory commissions have approved phase-ins that defer a portion of other postretirement benefits expense for future recovery. We recorded a regulatory asset for these future recoveries of $13 million as of December 31, 2006 and $14 million as of December 31, 2005. In addition, we recorded a regulatory liability of $4 million as of December 31, 2006 and $3 million as of December 31, 2005 for our expected expenses under the AGL Postretirement Plan. We expect to pay $7 million of insurance claims for the postretirement plan in 2007, but we do not anticipate making any additional contributions.

Effective December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law. This act provides for a prescription drug benefit under Medicare Part D as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D.

On July 1, 2004, the AGL Postretirement Plan was amended to remove prescription drug coverage for Medicare-eligible retirees effective January 1, 2006. Certain grandfathered NUI retirees participating in the NUI Postretirement Plan will continue receiving a prescription drug benefit through some period of time.

Notes

The following tables present details about our postretirement benefits.

In millions	AGL Postretirement Plan Dec. 31, 2006	AGL Postretirement Plan Dec. 31, 2005	NUI Postretirement Plan Dec. 31, 2005
Change in benefit obligation			
Benefit obligation at beginning of year[1]	**$107**	$ 98	$ 23
Service cost	**1**	1	—
Interest cost	**5**	5	1
Plan amendments	**—**	—	(7)
Actuarial (gain) loss	**(9)**	(6)	1
Benefits paid	**(9)**	(9)	(2)
Benefit obligation at end of year	**$ 95**	$ 89	$ 16
Change in plan assets			
Fair value of plan assets at beginning of year	**$ 59**	$ 49	$ 9
Actual return on plan assets	**5**	4	—
Employer contribution	**8**	6	2
Benefits paid	**(9)**	(9)	(2)
Fair value of plan assets at end of year	**$ 63**	$ 50	$ 9
Reconciliation of funded status			
Plan assets less benefit obligation at end of year	**$ (32)**	$(39)	$ (7)
Unrecognized loss	**—**	22	2
Unrecognized transition amount	**—**	1	—
Unrecognized prior service benefit	**—**	(23)	(6)
Accrued benefit cost[2]	**$ (32)**	$(39)	$(11)
Amounts recognized in the statement of financial position consist of			
Prepaid benefit cost	**$ —**	$ —	$ —
Accrued benefit liability	**(32)**	(39)	(11)
Accumulated OCI	**—**	—	—
Net amount recognized at year end[3]	**$ (32)**	$(39)	$(11)

[1] The NUI Postretirement Plan was terminated and eligible former participants became eligible to participate in the AGL Postretirement Plan on January 1, 2006.

[2] After adoption of SFAS 158 on December 31, 2006 these amounts are recorded and this reconciliation is no longer required.

[3] As of December 31, 2006, the AGL Postretirement Plan had $32 million of noncurrent liabilities and no noncurrent assets or current liabilities.

The following tables present details on the components of our net periodic benefit cost for the AGL Postretirement Plan and the NUI Postretirement Plan at the balance sheet dates.

In millions	AGL Postretirement Plan 2006	AGL Postretirement Plan 2005
Service cost	**$ 1**	$ 1
Interest cost	**5**	5
Expected return on plan assets	**(4)**	(4)
Amortization of prior service cost	**(4)**	(3)
Recognized actuarial loss	**1**	1
Net periodic postretirement benefit cost	**$(1)**	$—

In millions	NUI Postretirement Plan[1] 2005
Service cost	$—
Interest cost	1
Expected return on plan assets	—
Amortization of prior service cost	(1)
Recognized actuarial loss	—
Net periodic postretirement benefit cost	$—

[1] The NUI postretirement plan was terminated and eligible former participants became eligible to participate in the AGL Postretirement Plan on January 1, 2006.

There were no other changes in plan assets and benefit obligations recognized for the AGL and NUI Postretirement Plans for the year ended December 31, 2006. The 2007 estimated OCI amortization and refunds expected for the AGL Postretirement Plan are set forth in the following table.

In millions	2007
Amortization of transition obligation	$—
Amortization of prior service cost	(4)
Amortization of net loss	1
Refunds expected	—

The effects of SFAS 158 and AML adjustments for the AGL Postretirement Plan are set forth in the following table.

	AGL Retirement Plan				
In millions	Pre-SFAS 158 without AML adjustment	AML adjustment	Pre-SFAS 158 with AML adjustment	SFAS 158 adoption adjustments	Post SFAS 158
Prepaid pension asset (accrued pension liability)	$(40)	$—	$(40)	$ 8	$(32)
Intangible asset	—	—	—	—	—
Deferred tax asset	—	—	—	(3)	(3)
OCI—pension, net of tax	—	—	—	(5)	(5)
OCI—pension, pre-tax	—	—	—	(8)	(8)

The following table sets forth the assumed weighted average discount rates and rates of compensation increase used to determine benefit obligations for the AGL and NUI postretirement plans at December 31.

	AGL 2006	AGL 2005	NUI 2005[1]
Discount rate[1]	**5.8%**	5.5%	5.5%
Rate of compensation increase[1]	**4.0%**	4.0%	—%

[1] The NUI postretirement plan was terminated and eligible former participants became eligible to participate in the AGL postretirement plan on January 1, 2006.

The following tables present our weighted average assumed rates used to determine benefit obligations at the beginning of the period, January 1 for the AGL Postretirement Plan and December 1 for the NUI Postretirement Plan, and our weighted average assumed rates used to determine net periodic benefit cost at the beginning of these same periods.

AGL Postretirement Plan	**2006**[1]	2005	2004
Discount rate—benefit obligation	**5.8%**	5.5%	5.8%
Discount rate—net periodic benefit cost	**5.5%**	5.8%	6.3%
Expected return on plan assets	**8.5%**	8.8%	8.8%
Rate of compensation increase	**4.0%**	4.0%	4.0%

NUI Postretirement Plan[1]	2005	2004
Discount rate—benefit obligation	5.5%	5.8%
Discount rate—net periodic benefit cost	5.8%	5.8%
Expected return on plan assets	3.0%	2.0%
Rate of compensation increase	—	—

[1] The NUI postretirement plan was terminated and eligible former participants became eligible to participate in the AGL postretirement plan on January 1, 2006.

For information on the discount rate assumptions used for our postretirement plans, see the discussion contained in this Note 4 under the caption "Pension Benefits."

We consider the same factors in determining and selecting our assumptions for the overall expected long-term rate of return on plan assets as those considered in determining and selecting the overall expected long-term rate of return on plan assets for our retirement plans. For purposes of measuring our accumulated postretirement benefit obligation, the assumed pre-Medicare and post-Medicare health care inflation rates are as follows:

	AGL Postretirement Plan			
	Pre-medicare cost (pre-65 years old)		Post-medicare cost (post-65 years old)	
Assumed health care cost trend rates at December 31,	**2006**	2005	**2006**	2005
Health care cost trend rate assumed for next year	**2.5%**	2.5%	**2.5%**	2.5%
Rate to which the cost trend rate gradually declines	**2.5%**	2.5%	**2.5%**	2.5%
Year that the rate reaches the ultimate trend rate	**N/A**	N/A	**N/A**	N/A

Assumed health care cost trend rates at December 31,	NUI Postretirement Plan[1] 2005
Health care cost trend rate assumed for next year	2.5%
Rate to which the cost trend rate gradually declines	2.5%
Year that the rate reaches the ultimate trend rate	N/A

[1] The NUI postretirement plan was terminated and eligible former participants became eligible to participate in the AGL postretirement plan on January 1, 2006.

Effective January 2006, our health care trend rates for both the AGL Postretirement Plan and the NUI Postretirement Plan were capped at 2.5%. This cap limits the increase in our contributions to the annual change in the consumer price index (CPI). An annual CPI rate of 2.5% was assumed for future years.

Notes

Assumed health care cost trend rates impact the amounts reported for our health care plans. A one-percentage-point change in the assumed health care cost trend rates would have the following effects for the AGL Postretirement Plan and the NUI Postretirement Plan.

In millions	AGL Postretirement Plan One-percentage point Increase	Decrease
Effect on total of service and interest cost	$—	$—
Effect on accumulated postretirement benefit obligation	4	(4)

Our investment policies and strategies for our postretirement plans, including target allocation ranges, are similar to those for our retirement plans. We fund the plans annually; retirees contribute 20% of medical premiums, 50% of the medical premium for spousal coverage and 100% of the dental premium. Our postretirement plans weighted average asset allocations for 2006 and 2005 and our target asset allocation ranges are as follows:

In millions	Target range asset allocation	2006	2005
Equity	30%–80%	**66%**	52%
Fixed income	10%–40%	**32%**	46%
Real estate and other	10%–35%	**—%**	1%
Cash	0%–10%	**2%**	1%

The following table presents expected benefit payments covering the periods 2007 through 2016 for our retirement plans and postretirement health care plans. There will be benefit payments under these plans beyond 2016.

For the years ended Dec. 31, (in millions)	AGL Retirement Plan	NUI Retirement Plan	AGL Postretirement Plan
2007	$ 20	$ 7	$ 7
2008	20	6	7
2009	20	6	7
2010	20	6	7
2011	20	6	7
2012–2016	111	32	35

The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated OCI as of December 31, 2006.

In millions	AGL Retirement Plan	NUI Retirement Plan	AGL Postretirement Plan
Transition asset	$ —	$ —	$ 1
Prior service credit	(9)	(14)	(25)
Net gain	104	1	16
Accumulated OCI	95	(13)	(8)
Net amount recognized in statement of financial position	(65)	(14)	(32)
Cumulative employer contributions in excess of net periodic benefit cost prepaid (accrued)	$ 30	$(27)	$(40)

There were no other changes in plan assets and benefit obligations recognized in the AGL and NUI Retirement Plans or the AGL Postretirement Plan for the year ended December 31, 2006.

Employee Savings Plan Benefits

We sponsor the Retirement Savings Plus Plan (RSP), a defined contribution benefit plan that allows eligible participants to make contributions to their accounts up to specified limits. Under the RSP, we made matching contributions to participant accounts in the following amounts:

- $6 million in 2006
- $5 million in 2005
- $5 million in 2004

We also sponsor the Nonqualified Savings Plan (NSP), an unfunded, nonqualified plan similar to the RSP. The NSP provides an opportunity for eligible employees who could reach the maximum contribution amount in the RSP to contribute additional amounts for retirement savings. Our contributions to the NSP have not been significant in any year.

10

We're playing for keeps.

AGL Resources

2005 Annual Report

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We're playing for keeps.

AGL Resources

2005 Annual Report

We're playing for keeps.

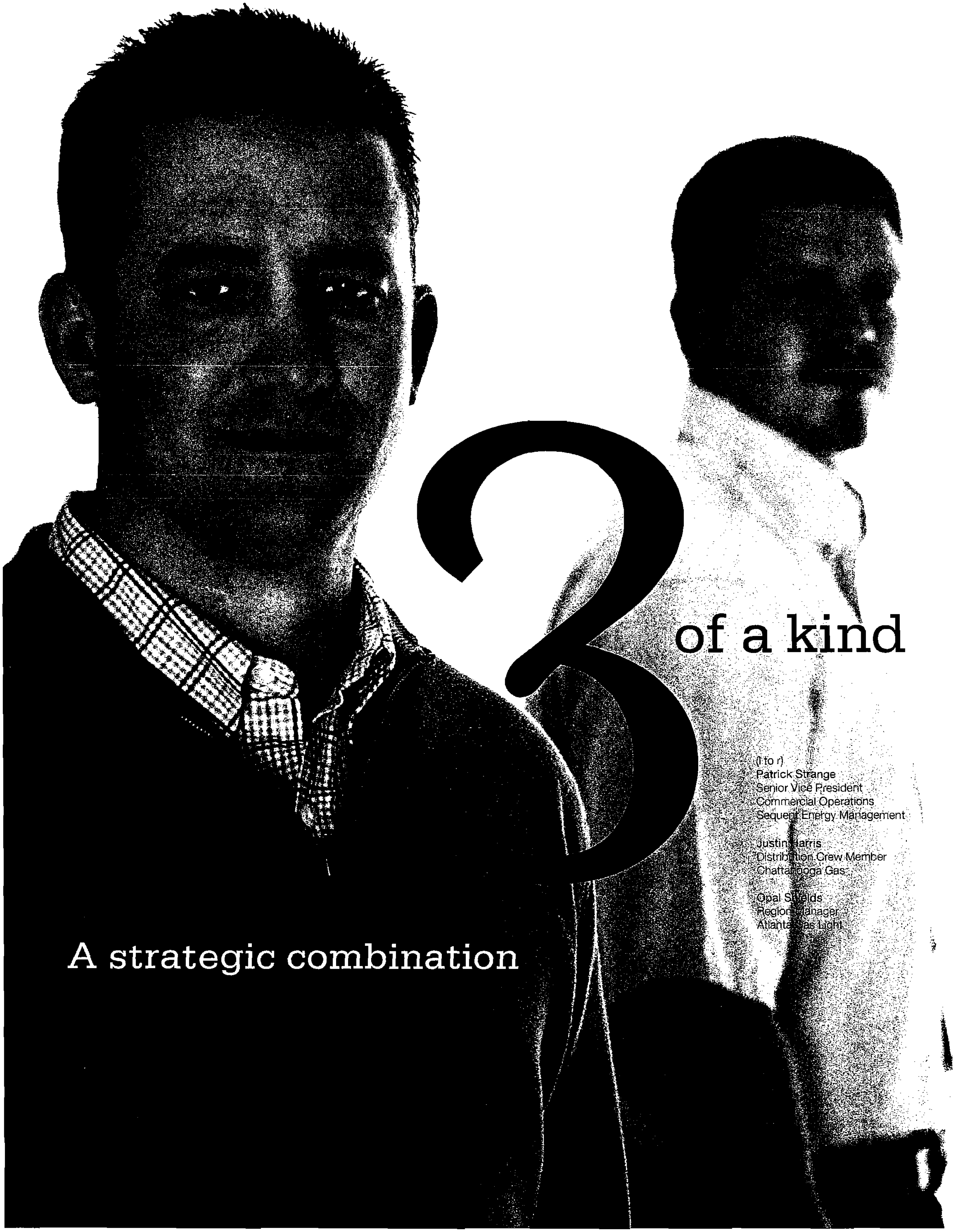
AGL Resources

2005 Annual Report

AGL Resources serves 2.2 million natural gas customers in six states through its utility subsidiaries. We provide asset management services to natural gas wholesale customers throughout the East and Midwest through our subsidiary, Sequent Energy Management. We market natural gas to customers in Georgia under the Georgia Natural Gas brand through a 70% ownership in SouthStar Energy Services. We own and operate other energy investments, among them Pivotal Jefferson Island Storage & Hub, a high-deliverability natural gas storage facility near the Henry Hub in Louisiana.

5 years ago, we announced we were going to radically transform our company into a value-generating institution for our shareholders. Some were doubtful. But with the hands we've played so far, we've proven our ability to deliver.

Year after year, AGL Resources has impressed the skeptics. We've continually increased consolidated earnings and improved customer service while operating within the regulated environment that governs our utilities. And we've continued to decrease expenses through a combination of business process improvements and discipline around capital spending. Our commitment to business integrity is strong. Our goals are clear. We stick to them. The result is an energy services holding company with a strong record of long-term, sustained performance that clearly distinguishes us from the pack.



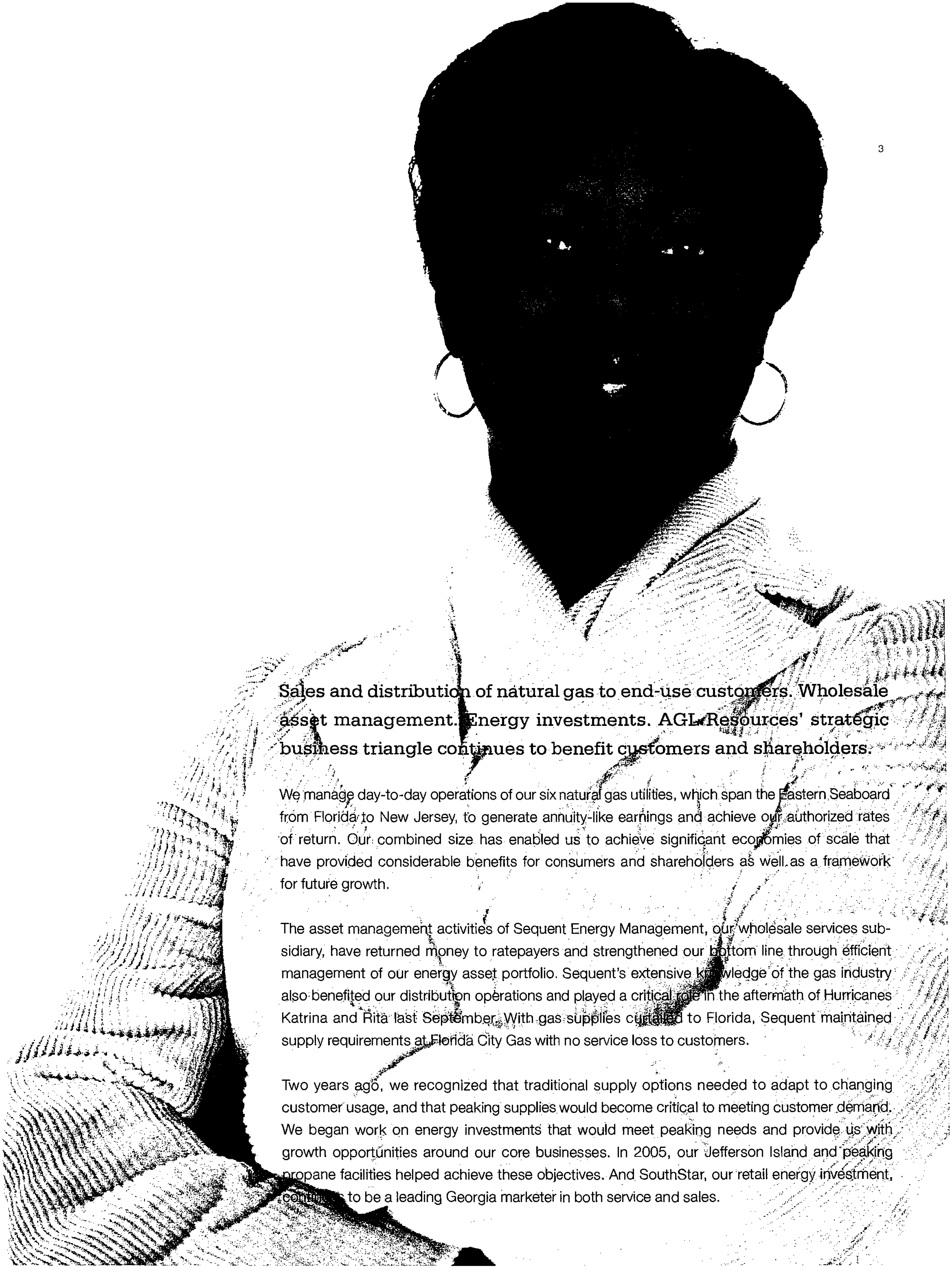
3 of a kind

(l to r)
Patrick Strange
Senior Vice President
Commercial Operations
Sequent Energy Management

Justin Harris
Distribution Crew Member
Chattanooga Gas

Opal Shields
Region Manager
Atlanta Gas Light

A strategic combination



Sales and distribution of natural gas to end-use customers. Wholesale asset management. Energy investments. AGL Resources' strategic business triangle continues to benefit customers and shareholders.

We manage day-to-day operations of our six natural gas utilities, which span the Eastern Seaboard from Florida to New Jersey, to generate annuity-like earnings and achieve our authorized rates of return. Our combined size has enabled us to achieve significant economies of scale that have provided considerable benefits for consumers and shareholders as well as a framework for future growth.

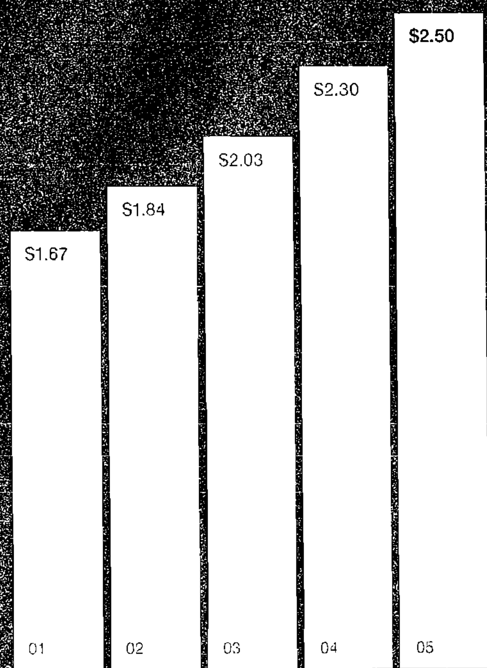
The asset management activities of Sequent Energy Management, our wholesale services subsidiary, have returned money to ratepayers and strengthened our bottom line through efficient management of our energy asset portfolio. Sequent's extensive knowledge of the gas industry also benefited our distribution operations and played a critical role in the aftermath of Hurricanes Katrina and Rita last September. With gas supplies curtailed to Florida, Sequent maintained supply requirements at Florida City Gas with no service loss to customers.

Two years ago, we recognized that traditional supply options needed to adapt to changing customer usage, and that peaking supplies would become critical to meeting customer demand. We began work on energy investments that would meet peaking needs and provide us with growth opportunities around our core businesses. In 2005, our Jefferson Island and peaking propane facilities helped achieve these objectives. And SouthStar, our retail energy investment, continues to be a leading Georgia marketer in both service and sales.

4 of a kind

Consecutive dividend increases.

Our strong cash position and anticipated cash flow gave us the opportunity to raise our dividend for the fourth time in three years, bringing our yield in line with the utility peer group. At an indicated annual dividend of $1.48 per share, our dividend is clearly supported by earnings yet preserves adequate capacity for investment in new projects. We have delivered on our promise to achieve returns in line with our long-term value proposition through the combination of a competitive dividend yield and consistent earnings growth.

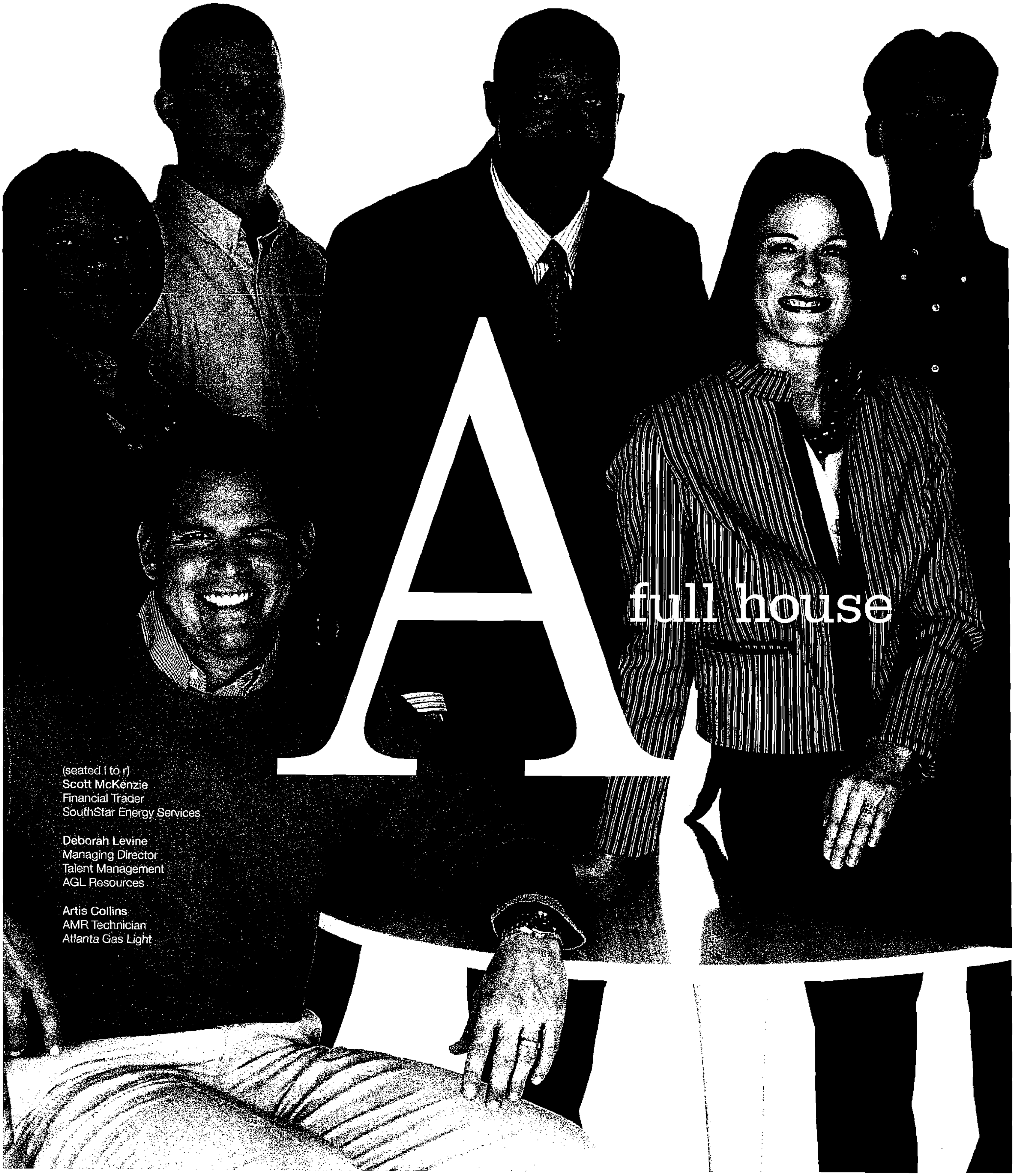


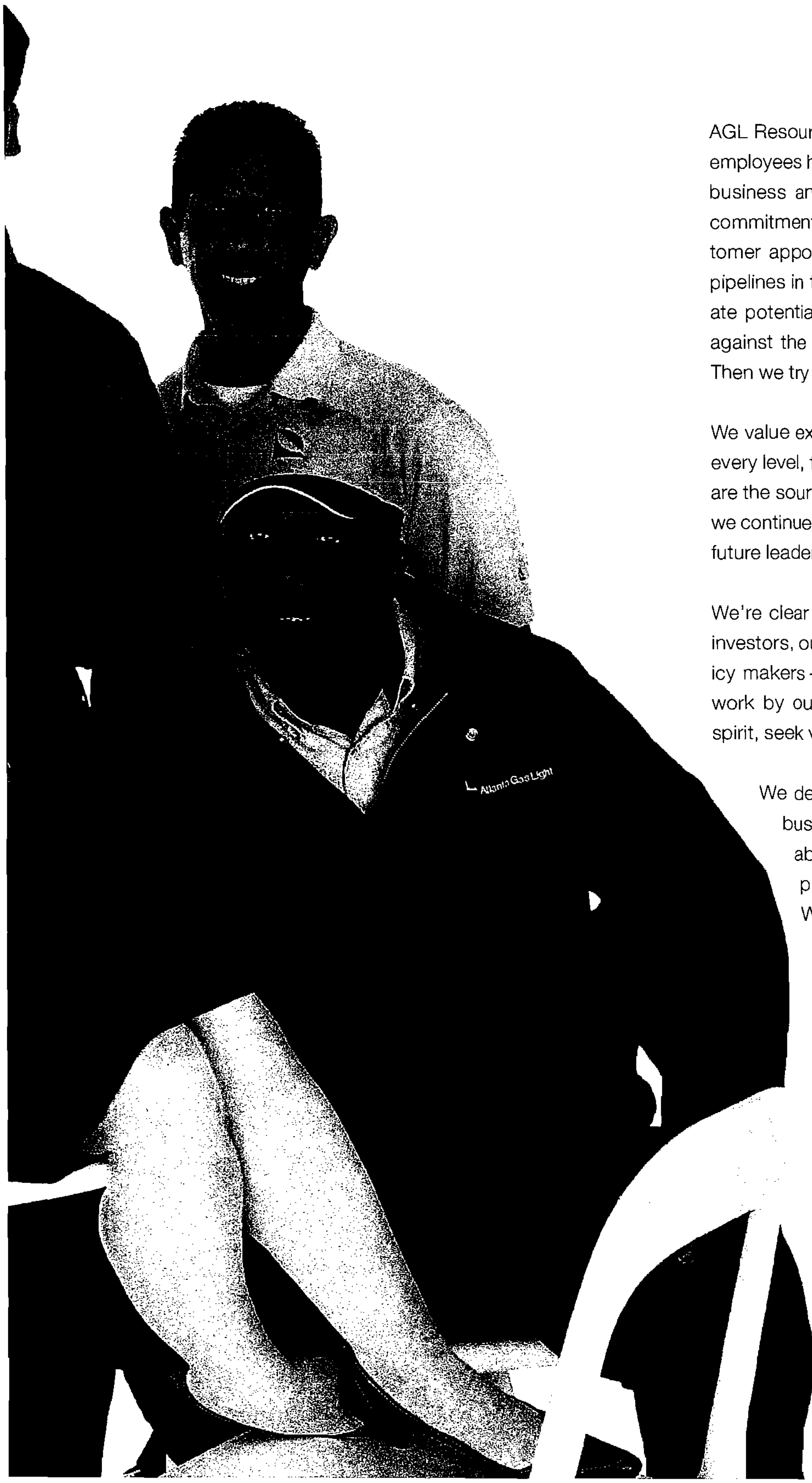
Calendar year basic earnings per share

straight

Another year of strong EPS growth

We have produced more than five consecutive years of strong earnings per share (EPS) growth through a combination of strategic decisions and business improvements. Our track record incorporates the acquisition and efficient integration of assets such as Virginia Natural Gas, NUI Corporation and Jefferson Island; a restructured SouthStar partnership and streamlined operations to achieve consistent earnings contributions; Sequent's growing capabilities as an asset manager for both affiliates and nonaffiliates; and a consistent focus on strict adherence to regulatory structures and relationships to ensure that both customers and shareholders benefit from our rigorous drive toward operational efficiencies and customer service improvements.


A full house
(seated l to r)
Scott McKenzie
Financial Trader
SouthStar Energy Services
Deborah Levine
Managing Director
Talent Management
AGL Resources
Artis Collins
AMR Technician
Atlanta Gas Light



AGL Resources believes a successful company is one where employees have a profound commitment to the success of the business and to one another. Our people demonstrate this commitment daily. Whether we service meters, schedule customer appointments from the call center, move gas through pipelines in the Midwest, manage a business division or evaluate potential growth opportunities, we benchmark ourselves against the best and pursue excellence in everything we do. Then we try to do it even better.

We value execution, imagination and productive innovation at every level, from the front line to top management. Our people are the source and driver of the ideas that make us better, and we continue to invest in their development because they *are* our future leaders.

We're clear about our commitments — to our customers, our investors, our communities, and our regulators and public policy makers — and we keep those commitments. We live and work by our core values: be honest, practice generosity of spirit, seek value and consistently work inside the lines.

We dedicate ourselves to outstanding service, superior business results, committed citizenship and the reliable, safe and transparent delivery of a high-quality product. Good enough is not what we're here for. We aim to set the standard.

(standing l to r)
Kinechie Johnson
Customer Service Team Leader
AGL Resources

Randy Stern
Distribution Crew Member
Virginia Natural Gas

Ralph Cleveland
Senior Vice President
Engineering and Operations
AGL Resources

Dat Tran
Chief Counsel
Unregulated Businesses
AGL Resources

Jose Caballero
Field Service Representative
Florida City Gas

wild card

AGL Resources' extensive crisis management plan is prepared to handle natural disasters—including hurricanes, a common threat in our service territories. Still, no one could have foreseen the level and breadth of destruction brought by the triple impact of Katrina, Rita and Wilma in 2005. Nevertheless, our company worked successfully with the hand nature dealt us.

As Rita headed for Houston, Sequent moved its trading and scheduling operations out of the hurricane's path. Working closely with AGL Resources' technology personnel in Georgia and Texas, Sequent's temporary offices—located 250 miles north of Houston—were up and fully functioning the next morning. We also brought along employees' families and pets so that our people could concentrate on doing their jobs assured of their loved ones' safety.

Functioning from a hotel conference room, our schedulers were able to track and confirm critical gas flows around the clock. Natural gas was dispatched from Sequent's managed and controlled resources, allowing us to serve customers when many of our competitors were unable to do so. To meet strong gas-fired power plant demand for electricity, Sequent directed gas from the Midwest and Northeast to the Southeast by continually rerouting gas on each pipeline nomination cycle. In spite of the challenges, we kept gas flowing to areas where it was most needed in a devastated landscape.

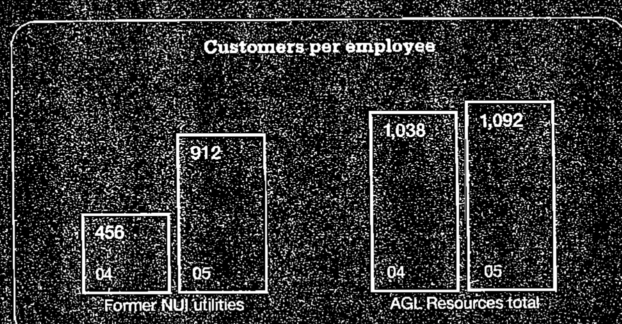
Jefferson Island also stepped up contingency planning in preparation for Katrina, helping interstate pipeline owners safely secure gas supplies in the anticipated path of the storm. Despite extensive flooding following Rita, Jefferson Island was up and serving customers within a couple of days.

high card

NUI Acquisition

We acquired NUI in November 2004 with a clear line of sight for consolidating its operations into our own and achieving the associated earnings benefit. We accomplished our goals ahead of schedule and within our capital spending budget for technology improvements.

We continue to apply the same operations model across our organization to ensure that our six utilities operate under fully integrated business processes and achieve the highest possible customer service standards. As a result of deploying new technology companywide — part of our integration strategy — we now have a scalable platform that supports future growth. Our intense focus on providing the best customer service, the cornerstone of this strategy, will also serve us well from a regulatory standpoint as we seek to become the "operator of choice" when consolidation opportunities arise.



2 our shareholders

Throughout 2005, AGL Resources continued to execute on our proven strategy to provide value-oriented investors with a superior investment proposition in the energy sector. Building on our strategic 2004 acquisitions of NUI Corporation and Jefferson Island Storage & Hub, we focused on generating significant cost savings and efficiencies from a larger and more geographically diverse portfolio. In addition, we continued implementation of a process improvement and technology platform that enhances the scalability of our operations. This will create an advantage as we pursue future growth and long-term shareholder value.

Financial Performance

The results of those efforts are clear. We grew earnings 9% to a record $2.50 per share in 2005. Our improved cash flow outlook enabled our Board of Directors to raise our annual dividend 19% in November 2005, to an indicated annual dividend of $1.48 per share. This increase marked the fourth raise in three years, moving our payout ratio closer to the peer group average and ensuring a competitive dividend yield relative to alternative investments. Total return to shareholders for the year, including reinvested dividends, was 8.6%, outperforming the S&P 500 (up 4.9%) and our peer group average (up 1.5%). Significantly, this growth came from every business unit, not just one or two.

CEO Transition

Our strong performance in 2005, like that of the previous five years, was achieved under the leadership of Paula Rosput Reynolds. During her tenure as CEO, Paula's steady hand and thoughtful strategy guided AGL Resources through some potentially dire straits and into our current position as one of our industry's most successful companies. On December 7, 2005, we announced Paula's resignation from the company

D. Raymond Riddle
Chairman

effective December 31, 2005 to become president and chief executive officer of a Seattle-based Fortune 500 company. The move represented a tremendous opportunity for Paula, and one that clearly reflected her extraordinary leadership ability and the outstanding results she achieved while part of the AGL Resources team.

In early December, the Board formed a search committee and engaged a well-known recruiting firm to identify a seasoned, high-caliber executive to lead the company and build on the great work accomplished to date. We anticipated the search process would be completed in a timely manner and would result in a new CEO with aspirations in line with current business goals. We exceeded expectations — in more ways than one — when we named John W. Somerhalder II the company's president, chief executive officer and newest member of the Board as of March 2.

John Somerhalder's 30 years of extensive regulated and non-regulated energy experience, his business acumen and leadership skills, his enthusiasm about the future of AGL Resources, and his commitment to customer service improvement and growing the bottom line are exactly the attributes we were searching for in our next chief executive. Under John's direction, our leadership team of talented and dedicated professionals, averaging nearly 20 years of business and regulatory experience, will continue to carry the company forward. We are privileged to have John on board.

2005 Milestones

Each year, we establish goals that guide our strategic decisions and provide the milestones to measure our progress along the way. In 2005, we laid out four primary goals: (1) integrate our acquisitions swiftly to meet the expectations of our investors; (2) establish a national reputation for customer service excellence by investing in systems, processes and people; (3) accelerate the pace of technology implementation and business process improvement; and (4) elevate our public policy profile with leading levels of transparency and collaboration.

In 2005, we completed the integration of our NUI and Jefferson Island acquisitions quickly and efficiently, achieving savings and delivering on promised earnings accretion. As part of the integration process, we set out to dramatically improve the customer experience in each of our utility service areas. The results were evident. Late in the year, J.D. Power and Associates, in a ranking of gas utility residential service providers, recognized Virginia Natural Gas as one of the top five utilities in the nation in customer satisfaction. The same ranking listed Elizabethtown Gas, the New Jersey utility we acquired as part of the NUI acquisition in late 2004, as one of the most improved utilities.

We continued to identify and implement technology and other process improvements that have moved us closer to our vision: a "one company" operational platform that eliminates duplicate systems and disparate processes among our companies, and establishes the possibilities of virtual workforce automation while creating a platform for scalability. Those improved technology capabilities proved themselves during Hurricane Rita, when we temporarily relocated our Sequent trading floor from Houston to Richardson, Texas with virtually no business interruption. While service disruptions were prevalent throughout the disaster-stricken region, we maintained a cohesive working environment. This allowed us to communicate effectively with markets and suppliers, providing critical assistance to those who needed it.

Andrew W. Evans
Senior Vice President and CFO

We also continued to make substantial progress on the public policy front during 2005. By working cooperatively with our regulators, we were able to negotiate a settlement in the Atlanta Gas Light rate case providing customers with stabilized rates for a five-year period. We are seeking a similar rate treatment as part of our ongoing rate case in Virginia. Throughout the year, we fully participated in critical industry dialogue on the economic and operational viability of liquefied natural gas and other supply and infrastructure options. We are continually exploring ways to address current supply constraint and peaking issues, and to reduce our reliance on natural gas from the Gulf Coast region.

2006 Goals

Our goals for 2006 have evolved from our achievements in 2005. Our philosophy is that we are never finished refining the process, and there is always room for improvement.

First, we will operate each of our businesses to deliver on our longstanding commitment to superior earnings and income growth. As an owner of the company, you can expect us to be good stewards of your investment by establishing threshold returns before deploying significant capital. We're proud of our reputation for being a prudent investor and operator, and we intend to leverage that reputation as we seek new opportunities.

Second, we will continue to build a process-driven culture that supports scalability and includes global commerce. Implementing enterprise technology was a first step. We must now compete in a global marketplace of service providers. We have already made significant headway in identifying routine operational and financial processes within our current businesses that might benefit from either global sourcing or restructuring to shift and reduce our cost burden.

Third, we will deliver exceptional retail and wholesale customer service through superior logistics. In 2006, we will build on the improved reputation and customer service processes of our utilities by continuing to elevate the customer experience. We intend to implement a wide array of improvements — such as enhanced automated dispatch to ensure appointment times are met — aimed at making a customer's experience with any of our six utilities as pleasant and efficient as possible.

Fourth, we will invest to make people our competitive edge in sustaining enterprise excellence. Without a high-performance culture and talented professionals who are trained and compensated appropriately, and equipped with the resources they need to succeed, we know that our first three goals cannot be accomplished.

We look forward to updating you on our progress in the months ahead. AGL Resources will continue to create value in everything we do. We're playing for keeps.

D. Raymond Riddle
Chairman
March 2, 2006

Andrew W. Evans
Senior Vice President and CFO
March 2, 2006

we're the one to watch

Provide superior growth in earnings and dividends.

We will aim for flawless execution in our existing businesses. We will continually seek growth opportunities. And we will exercise rigorous discipline in evaluating those opportunities.

Be relentless in business process improvement.

We will always look for better ways of doing things. We will demand real returns from investments in technology, systems and equipment. And we will identify processes that may be better accomplished through global sourcing or restructuring.

Build on our growing reputation for customer service excellence through enhanced logistics.

We will continue to implement improvements to make our customers' experience pleasant, efficient and worthwhile. We will deliver exceptional retail and wholesale customer service. We will benchmark ourselves against the best.

Make our people the competitive edge.

We will invest in the ability of our people to apply imagination and search for innovations. We will equip them with the resources they need to succeed. And we will clearly articulate our business goals and aspirations.

at a glance

Distribution Operations

Atlanta Gas Light is the largest natural gas distributor in the Southeast in terms of customers, serving 237 communities in the state of Georgia. It provides gas delivery service to more than 1.5 million residential, commercial and industrial customers and delivers approximately 232 million dekatherms (MMDth) of gas annually. It owns and operates more than 30,000 miles of pipeline and three liquefied natural gas (LNG) plants.

Chattanooga Gas provides retail natural gas sales and transportation services to approximately 61,000 residential, commercial and industrial customers in Hamilton County and Bradley County, Tennessee. Chattanooga Gas delivers approximately 16 MMDth of gas annually. It also owns and operates more than 1,500 miles of pipeline and one LNG plant.

Elizabethtown Gas provides natural gas service to approximately 266,000 residential, commercial and industrial customers in northeastern and east central New Jersey. It delivers approximately 59 MMDth of gas annually through more than 4,900 miles of pipeline.

Elkton Gas provides natural gas service to approximately 5,800 residential, commercial and industrial customers in northeastern Maryland. Elkton Gas delivers approximately 1 MMDth of gas annually through more than 80 miles of pipeline.

Florida City Gas provides natural gas service to approximately 103,000 residential, commercial and industrial customers in southeastern and east central Florida. It delivers approximately 10 MMDth of gas annually through more than 3,100 miles of pipeline.

Virginia Natural Gas provides natural gas service to more than 261,000 residential, commercial and industrial customers in southeastern Virginia. It delivers approximately 36 MMDth of gas annually through more than 5,100 miles of pipeline. It also owns and operates a 156-mile high-pressure, large-diameter transmission pipeline serving major wholesale customers.

Retail Energy Operations

SouthStar Energy Services is a joint venture operating in Georgia under the trade name Georgia Natural Gas. The business supplies natural gas to more than 531,000 retail and commercial customers in Georgia and 300 industrial customers throughout the Southeast.

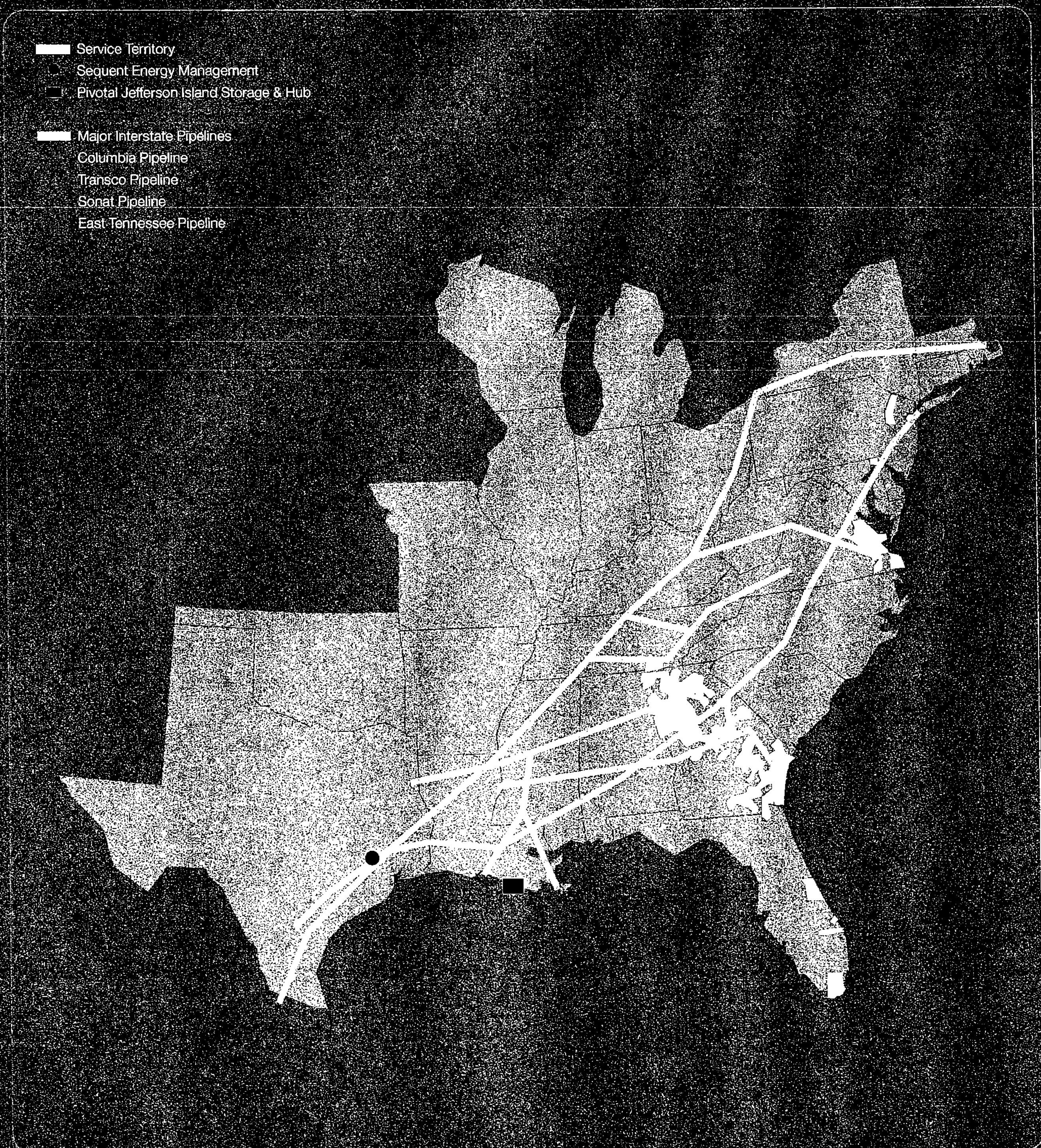
Wholesale Services

Sequent Energy Management provides customers in the Midwest and eastern half of the United States the ability to optimize their natural gas asset portfolio and increase cost effectiveness from wellhead to burner tip. Services include natural gas asset management, producer and storage services, and full-requirements supply, including peaking needs.

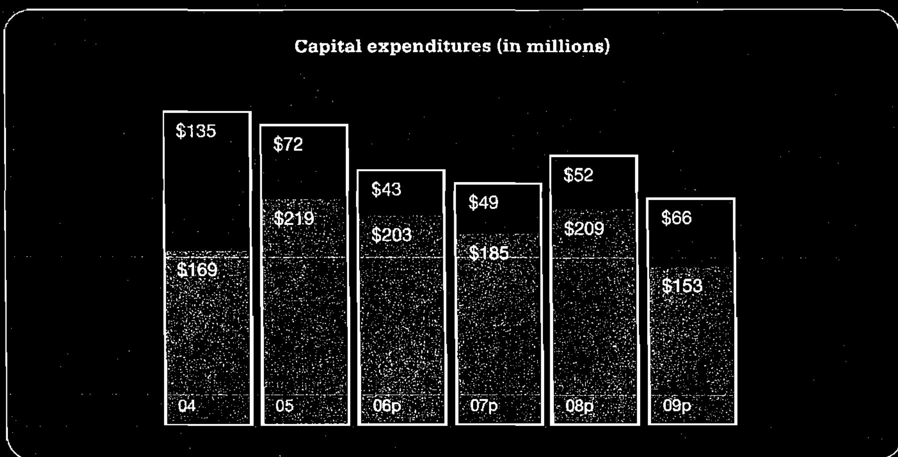
Energy Investments

The company operates **Pivotal Jefferson Island Storage & Hub**, a high-deliverability natural gas storage facility in Louisiana. The facility consists of two salt dome storage caverns with 10 billion cubic feet (Bcf) of total capacity and about 7 Bcf of working gas capacity. In addition, the company manages the operation of Pivotal Propane of Virginia, a peaking facility in northern Virginia.

AGL Networks is a carrier-neutral provider that leases telecommunications fiber to a variety of customers in the Atlanta, Georgia and Phoenix, Arizona metropolitan areas. AGL Networks provides conduit and dark fiber to its customers under long-term lease arrangements, as well as telecommunications construction services.


Service Territory
Sequent Energy Management
Pivotal Jefferson Island Storage & Hub
Major Interstate Pipelines
Columbia Pipeline
Transco Pipeline
Sonat Pipeline
East Tennessee Pipeline

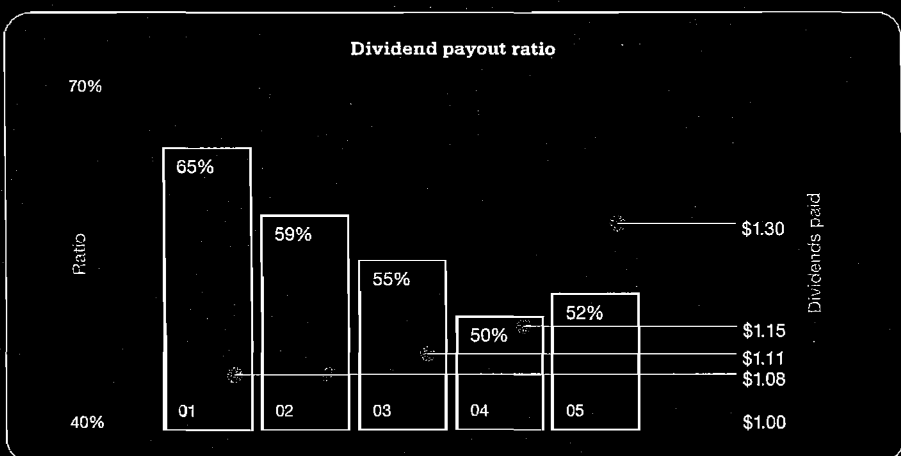
financial charts



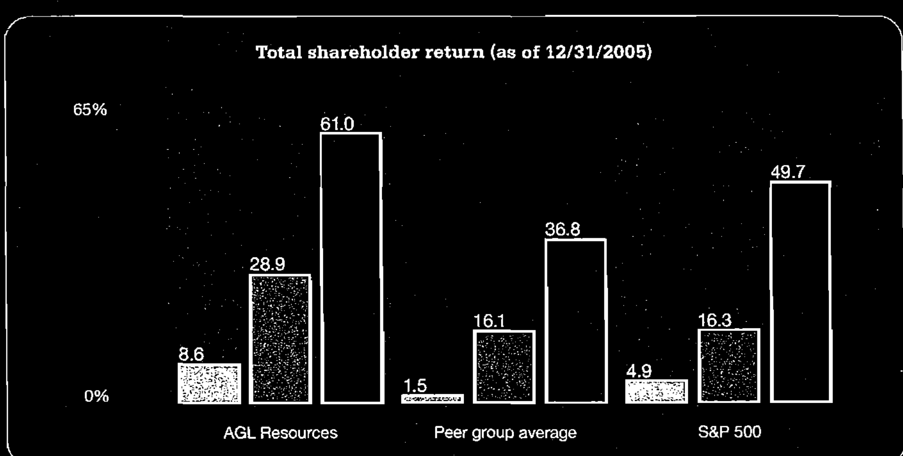
A disciplined approach to managing capital investments should provide significant opportunity for debt reduction, reinvestment in the business, or returns to shareholders in the form of dividend increases or stock repurchases.

Mandated capital*
*Includes Atlanta Gas Light pipeline replacement costs and environmental remediation expenses for Atlanta Gas Light and the former NUI utilities

Other capital expenditures



AGL Resources remains focused on maintaining a competitive dividend yield and a payout ratio near the average of our peer group of utilities. The 19% dividend increase announced in November 2005 raised our indicated annual dividend to $1.48 per share.



The peer group average includes seven natural gas utilities with characteristics similar to AGL Resources.

One-year

Two-year

Three-year

financials

AGL Capital AGL Capital Corporation

AGL Networks AGL Networks, LLC

Atlanta Gas Light Atlanta Gas Light Company

Chattanooga Gas Chattanooga Gas Company

Credit Facility Credit agreement supporting our commercial paper program

EBIT Earnings before interest and taxes, a non-GAAP measure that includes operating income, other income, equity in SouthStar's income, minority interest in SouthStar's earnings, donations and gain on sales of assets and excludes interest and tax expense; as an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, operating income or net income as determined in accordance with GAAP

ERC Environmental remediation costs

FASB Financial Accounting Standards Board

Florida Commission Florida Public Service Commission

GAAP Accounting principles generally accepted in the United States of America

Georgia Commission Georgia Public Service Commission

Henry Hub The Henry Hub, located in Louisiana, is the largest centralized point for natural gas spot and futures trading in the United States. NYMEX uses the Henry Hub as the point of delivery for its natural gas futures contracts. Many natural gas marketers also use the Henry Hub as their physical contract delivery point or their price benchmark for spot trades of natural gas.

LNG Liquefied natural gas

Marketers Marketers selling retail natural gas in Georgia and certificated by the Georgia Public Service Commission

Medium-term notes Notes issued by Atlanta Gas Light with scheduled maturities between 2012 and 2027 bearing interest rates ranging from 6.6% to 9.1%

NJBPU New Jersey Board of Public Utilities

NYMEX New York Mercantile Exchange, Inc.

OCI Other comprehensive income

Operating margin A measure of income, calculated as revenues minus cost of gas, that excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain on the sale of our Caroline Street campus; these items are included in our calculation of operating income as reflected in our statements of consolidated income. Operating margin should not be considered an alternative to, or more meaningful than, operating income or net income as determined in accordance with GAAP

Pivotal Jefferson Island Pivotal Jefferson Island Storage & Hub, LLC

Pivotal Propane Pivotal Propane of Virginia, Inc.

Pivotal Utility Pivotal Utility Holdings, Inc., parent company of Elizabethtown Gas, Elkton Gas and Florida City Gas

PGA Purchased gas adjustment

PRP Pipeline replacement program

PUHCA Public Utility Holding Company Act of 1935, as amended

Sequent Sequent Energy Management, L.P.

SFAS Statement of Financial Accounting Standards

SouthStar SouthStar Energy Services LLC

Virginia Commission Virginia State Corporation Commission

Virginia Natural Gas Virginia Natural Gas, Inc.

APB 20 Accounting Principles Board (APB) Opinion No. 20, "Accounting Changes"

APB 25 APB Opinion No. 25, "Accounting for Stock Issued to Employees"

EITF 98-10 Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities"

EITF 99-02 EITF Issue No. 99-02, "Accounting for Weather Derivatives"

EITF 02-03 EITF Issue No. 02-03, "Issues Involved in Accounting for Contracts under EITF Issue No. 98-10, 'Accounting for Contracts Involved in Energy Trading and Risk Management Activities'"

FIN 46 & FIN 46R FASB Interpretation No. (FIN) 46, "Consolidation of Variable Interest Entities"

FIN 47 FIN 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143"

SFAS 5 Statement of Financial Accounting Standards (SFAS) No. 5, "Accounting for Contingencies"

SFAS 13 SFAS No. 13, "Accounting for Leases"

SFAS 71 SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"

SFAS 109 SFAS No. 109, "Accounting for Income Taxes"

SFAS 123 & SFAS 123R SFAS No. 123, "Accounting for Stock-Based Compensation"

SFAS 131 SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information"

SFAS 133 SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"

SFAS 141 SFAS No. 141, "Business Combinations"

SFAS 142 SFAS No. 142, "Goodwill and Other Intangible Assets"

SFAS 149 SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"

SFAS 154 SFAS No. 154, "Accounting Changes and Error Corrections"

Selected financial data about us is set forth in the table below. We derived the data in the table from our audited financial statements. You should read the data in the table in conjunction with our consolidated financial statements and related notes. On September 30, 2001, our Board of Directors elected to change our fiscal year end from September 30 to December 31, effective October 1, 2001. We refer to the three months ended December 31, 2001 as the "Transition period" in the table below.

Dollars and shares in millions, except per share amounts	2005	2004	2003	2002	Transition period	2001
Income statement data						
Operating revenues	**$2,718**	$1,832	$ 983	$ 877	$ 204	$ 946
Cost of gas	**1,626**	995	339	268	49	327
Operating margin	**1,092**	837	644	609	155	619
Operating expenses						
Operation and maintenance	**477**	377	283	274	68	267
Depreciation and amortization	**133**	99	91	89	23	100
Taxes other than income taxes	**40**	29	28	29	6	33
Total operating expenses	**650**	505	402	392	97	400
Gain on sale of Caroline Street campus	**—**	—	16	—	—	—
Operating income	**442**	332	258	217	58	219
Equity in earnings of SouthStar Energy Services LLC	**—**	—	46	27	4	14
Other (loss) income	**(1)**	—	(6)	3	1	4
Minority interest	**(22)**	(18)	—	—	—	—
Interest expense	**(109)**	(71)	(75)	(86)	(24)	(98)
Earnings before income taxes	**310**	243	223	161	39	139
Income taxes	**117**	90	87	58	14	50
Income before cumulative effect of change in accounting principle	**193**	153	136	103	25	89
Cumulative effect of change in accounting principle, net of $5 in income taxes	**—**	—	(8)	—	—	—
Net income	**$ 193**	$ 153	$ 128	$ 103	$ 25	$ 89
Common stock data						
Weighted average shares outstanding—basic	**77.3**	66.3	63.1	56.1	55.3	54.5
Weighted average shares outstanding—fully diluted	**77.8**	67.0	63.7	56.6	55.6	54.9
Total shares outstanding[1]	**77.8**	76.7	64.5	56.7	55.6	55.1
Earnings per share—basic	**$ 2.50**	$ 2.30	$ 2.03	$ 1.84	$ 0.45	$ 1.63
Earnings per share—fully diluted	**$ 2.48**	$ 2.28	$ 2.01	$ 1.82	$ 0.45	$ 1.62
Dividends per share	**$ 1.30**	$ 1.15	$ 1.11	$ 1.08	$ 0.27	$ 1.08
Dividend payout ratio	**52%**	50%	55%	59%	60%	66%
Book value per share[2]	**$19.27**	$18.04	$14.66	$12.52	$12.41	$12.20
Market value per share[3]	**$34.81**	$33.24	$29.10	$24.30	$23.02	$19.97
Balance sheet data[1]						
Total assets	**$6,251**	$5,637	$3,972	$3,742	$3,454	$3,368
Long-term liabilities	**737**	682	647	702	671	711
Minority interest	**38**	36	—	—	—	—
Capitalization						
Long-term debt (excluding current portion)	**1,615**	1,623	956	994	1,015	1,065
Common shareholders' equity	**1,499**	1,385	945	710	690	671
Total capitalization	**$3,114**	$3,008	$1,901	$1,704	$1,705	$1,736
Financial ratios[1]						
Capitalization						
Long-term debt	**52%**	54%	50%	58%	60%	61%
Common shareholders' equity	**48**	46	50	42	40	39
Total	**100%**	100%	100%	100%	100%	100%
Return on average common shareholders' equity	**13.4%**	13.1%	15.5%	14.7%	14.6%	13.8%

[1] As of the last day of the fiscal period.

[2] Common shareholders' equity divided by total outstanding common shares as of the last day of the fiscal period.

[3] Closing price of common stock on the New York Stock Exchange as of the last trading day of the fiscal period.

The determination of future expected costs involves judgment. Factors that must be considered in estimating the future expected costs are projected capital expenditure spending and remaining footage of infrastructure to be replaced for the remaining years of the program. Atlanta Gas Light recorded a long-term liability of $235 million as of December 31, 2005 and $242 million as of December 31, 2004, which represented engineering estimates for remaining capital expenditure costs in the PRP. As of December 31, 2005, Atlanta Gas Light had recorded a current liability of $30 million, representing expected PRP expenditures for the next 12 months. We report these estimates on an undiscounted basis. If the recorded liability for PRP had been higher or lower by $10 million, Atlanta Gas Light's expected recovery would have changed by approximately $1 million.

Environmental Remediation Liabilities Atlanta Gas Light historically reported estimates of future remediation costs based on probabilistic models of potential costs. We report these estimates on an undiscounted basis. As we continue to conduct the actual remediation and enter cleanup contracts, Atlanta Gas Light is increasingly able to provide conventional engineering estimates of the likely costs of many elements of its remediation program. These estimates contain various engineering uncertainties, and Atlanta Gas Light continuously attempts to refine and update these engineering estimates.

Our latest available estimate as of December 31, 2005 for those elements of the remediation program with in-place contracts or engineering cost estimates is $12 million for Atlanta Gas Light's Georgia and Florida sites. This is a reduction of $24 million from the estimate as of December 31, 2004 of projected engineering and in-place contracts, resulting from program expenditures during 2005. For elements of the remediation program where Atlanta Gas Light still cannot perform engineering cost estimates, considerable variability remains in available estimates. The estimated remaining cost of future actions at these sites is $15 million. Atlanta Gas Light estimates certain other costs it pays related to administering the remediation program and remediation of sites currently in the investigation phase. Through January 2007, Atlanta Gas Light estimates the administration costs to be $4 million. Beyond 2007, these costs are not estimable.

Atlanta Gas Light's environmental remediation liability is included in its corresponding regulatory asset. As of December 31, 2005, the regulatory asset was $133 million, which is a combination of the accrued remediation liability and unrecovered cash expenditures. Atlanta Gas Light's estimate does not include other potential expenses, such as unasserted property damage, personal injury or natural resource damage claims, unbudgeted legal expenses, or other costs for which it may be held liable but with respect to which the amount cannot be reasonably forecast. Atlanta Gas Light's recovery of environmental remediation costs is subject to review by the Georgia Commission, which may seek to disallow the recovery of some expenses.

In New Jersey, Elizabethtown Gas is currently conducting remediation activities with oversight from the New Jersey Department of Environmental Protection. Although the actual total cost of future environmental investigation and remediation efforts cannot be estimated with precision, the range of reasonably probable costs is $57 million to $104 million. As of December 31, 2005, no value within this range is better than any other value, so we recorded a liability of $57 million.

The NJBPU has authorized Elizabethtown Gas to recover prudently incurred remediation costs for the New Jersey properties through its remediation adjustment clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $63 million, inclusive of interest, as of December 31, 2005, reflecting the future recovery of both incurred costs and future remediation liabilities in the state of New Jersey. Elizabethtown Gas has also been successful in recovering a portion of remediation costs incurred in New Jersey from its insurance carriers and continues to pursue additional recovery. As of December 31, 2005, the variation between the amounts of the environmental remediation cost liability recorded in the consolidated balance sheet and the associated regulatory asset is due to expenditures for environmental investigation and remediation exceeding recoveries from ratepayers and insurance carriers.

We also own several former NUI remediation sites located outside of New Jersey. One site, in Elizabeth City, North Carolina, is subject to an order by the North Carolina Department of Energy and Natural Resources. We do not have precise estimates for the cost of investigating and remediating this site, although preliminary estimates for these costs range from $10 million to $17 million. As of December 31, 2005, we have recorded a liability of $10 million related to this site. There is another site in North Carolina where investigation and remediation is probable, although no regulatory order exists and we do not believe costs associated with this site can be reasonably estimated. In addition, there are as many as six other sites with which NUI had some association, although no basis for liability has been asserted. We do not believe that costs to investigate and remediate these sites, if any, can be reasonably estimated at this time.

With respect to these costs, we currently pursue or intend to pursue recovery from ratepayers, former owners and operators and insurance carriers. Although we have been successful in recovering a portion of these remediation costs from our insurance carriers, we are not able to express a belief as to the success of additional recovery efforts. We are working with the regulatory agencies to prudently manage our remediation costs so as to mitigate the impact of such costs on both ratepayers and shareholders.

Derivatives and Hedging Activities SFAS 133, as updated by SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149), established accounting and reporting standards which require that every derivative financial instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or a liability measured at its fair value. However, if the derivative transaction qualifies for and is designated as a normal purchase and sale, it is exempted from the fair value accounting treatment of SFAS 133, as updated by SFAS 149, and is accounted for using traditional accrual accounting.

SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, SFAS 133 allows a derivative's gains and losses to offset related results on the hedged item in the income statement in the case of a fair value hedge, or to record the gains and losses in other comprehensive income (OCI) until maturity in the case of a cash flow hedge. Additionally, SFAS 133 requires that a company formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment. Two areas where SFAS 133 applies are interest rate swaps and gas commodity contracts at Sequent and SouthStar. Our derivative and hedging activities are described in further detail in Note 4.

Interest Rate Swaps We designate our interest rate swaps as fair value hedges as defined by SFAS 133, which allows us to designate derivatives that hedge exposure to changes in the fair value of a recognized asset or liability. We record the gain or loss on fair value hedges in earnings in the period of change, together with the offsetting loss or gain on the hedged item attributable to the risk being hedged. The effect of this accounting is to reflect in earnings only that portion of the hedge that is not effective in achieving offsetting changes in fair value.

Commodity-related Derivative Instruments We are exposed to risks associated with changes in the market price of natural gas. Elizabethtown Gas utilizes certain derivatives for nontrading purposes to hedge the impact of market fluctuations on assets, liabilities and other contractual commitments. Pursuant to SFAS 133, such derivative products are marked to market each reporting period. Pursuant to regulatory requirements, realized gains and losses related to such derivatives are reflected in purchased gas costs and included in billings to customers. Unrealized gains and losses are reflected as a regulatory asset (loss) or liability (gain), as appropriate, in the consolidated balance sheet. Through Sequent and SouthStar, we use derivative instruments to reduce our exposure to the risk of changes in the price of natural gas. Sequent recognizes the change in value of derivative instruments as an unrealized gain or loss in revenues in the period when the market value of the instrument changes. Sequent recognizes cash inflows and outflows associated with the settlement of its risk management activities in operating cash flows, and reports these settlements as receivables and payables in the balance sheet separately from the risk management activities reported as energy marketing receivables and trade payables.

Under our risk management policy, we attempt to mitigate substantially all our commodity price risk associated with Sequent's natural gas storage portfolio and lock in the economic margin at the time we enter into purchase transactions for our stored natural gas. We purchase natural gas for storage when the current market price we pay plus storage costs is less than the market price we could receive in the future. We lock in the economic margin by selling NYMEX futures contracts or other over-the-counter derivatives in the forward months corresponding with our withdrawal periods. We use contracts to sell natural gas at that future price to substantially lock in the profit margin we will ultimately realize when the stored natural gas is actually sold. These contracts meet the definition of a derivative under SFAS 133.

The purchase, storage and sale of natural gas are accounted for differently from the derivatives we use to mitigate the commodity price risk associated with our storage portfolio. The difference in accounting can result in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated. We do not currently use hedge accounting under SFAS 133 to account for this activity.

Earnings Per Common Share

We compute basic earnings per common share by dividing our income available to common shareholders by the daily weighted average number of common shares outstanding. Fully diluted earnings per common share reflect the potential reduction in earnings per common share that could occur when potentially dilutive common shares are added to common shares outstanding.

We derive our potentially dilutive common shares by calculating the number of shares issuable under performance units and stock options. The future issuance of shares underlying the performance units depends on the satisfaction of certain performance criteria. The future issuance of shares underlying the outstanding stock options depends on whether the exercise prices of the stock options are less than the average market price of the common shares for the respective periods. No items are antidilutive. The following table shows the calculation of our fully diluted earnings per share for the periods presented if performance units currently earned under the plan ultimately vest and if stock options currently exercisable at prices below the average market prices are exercised.

In millions	2005	2004	2003
Denominator for basic earnings per share[1]	**77.3**	66.3	63.1
Assumed exercise of potential common shares	**0.5**	0.7	0.6
Denominator for fully diluted earnings per share	**77.8**	67.0	63.7

[1] Daily weighted average shares outstanding.

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include our regulatory accounting, the allowance for doubtful accounts, allowance for contingencies, pipeline replacement program (PRP) accruals, environmental liability accruals, unbilled revenue recognition, pension and postretirement obligations, derivative and hedging activities, and purchase price allocations. Actual results could differ from those estimates.

2

Acquisition of NUI

On November 30, 2004, we acquired NUI for approximately $825 million, including the assumption of $709 million in debt. The acquisition significantly expands our existing natural gas utilities, storage and pipeline businesses. During 2005, we adjusted our purchase price allocation by $74 million for additional known items, including adjustments related to pension obligations; severance; lease obligations related to NUI's former corporate offices; environmental remediation liabilities; income tax liabilities; and asset sales. In connection with the acquisition, we incurred $25 million in employee-related restructuring charges. As of December 31, 2005, $5 million of these payments remained to be paid. Our purchase price allocation as of December 31, 2004 and 2005 and the goodwill adjustments are indicated in the following table.

In millions	Dec. 31, 2004	Adjustments	Dec. 31, 2005
Purchase price	$ 825	$ —	**$ 825**
Current assets	299	(1)	**298**
Property, plant and equipment	612	(15)	**597**
Other long-term assets	117	(21)	**96**
Goodwill	157	74	**231**
Current liabilities excluding debt	(108)	(4)	**(112)**
Short-term debt and capital leases	(502)	—	**(502)**
Long-term debt and capital leases	(207)	—	**(207)**
Other long-term liabilities	(143)	(31)	**(174)**
Equity	225	2	**227**

We believe the acquisition resulted in the recognition of goodwill primarily because of the strength of NUI's underlying assets and the synergies and opportunities in the regulated utilities.

5

Regulatory Assets and Liabilities

We have recorded regulatory assets and liabilities in our consolidated balance sheets in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). Our regulatory assets and liabilities, and associated liabilities for our unrecovered PRP costs and unrecovered environmental remediation costs (ERC), are summarized in the table below.

In millions	December 31, 2005	2004
Regulatory assets		
Unrecovered PRP costs	**$303**	$361
Unrecovered ERC	**196**	200
Unrealized loss on hedging derivatives	**17**	6
Unrecovered postretirement benefit costs	**14**	14
Unrecovered seasonal rates	**11**	11
Unrecovered PGA	**8**	2
Regulatory tax asset	**1**	2
Other	**9**	20
Total regulatory assets	**$559**	$616
Regulatory liabilities		
Accumulated removal costs	**$ 94**	$ 94
Deferred PGA	**36**	60
Unrealized gain on hedging derivatives	**21**	6
Unamortized investment tax credit	**19**	20
Regulatory tax liability	**15**	14
Other	**6**	12
Total regulatory liabilities	**191**	206
Associated liabilities		
PRP costs	**265**	327
ERC	**97**	90
Total associated liabilities	**362**	417
Total regulatory and associated liabilities	**$553**	$623

Our regulatory assets are recoverable through either rate riders or base rates specifically authorized by a state regulatory commission. Base rates are designed to provide both a recovery of cost and a return on investment during the period rates are in effect. As such, all our regulatory assets are subject to review by the respective state regulatory commission during any future rate proceedings. In the event that the provisions of SFAS 71 were no longer applicable, we would recognize a write-off of net regulatory assets (regulatory assets less regulatory liabilities) that would result in a charge to net income, which would be classified as an extraordinary item. However, although the natural gas distribution industry is becoming increasingly competitive, our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under SFAS 71 remains appropriate. It is also our opinion that all regulatory assets are recoverable in future rate proceedings, and therefore we have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a rate rider.

All the regulatory assets included in the table above are included in base rates except for the unrecovered PRP costs, unrecovered ERC and deferred PGA, which are recovered through specific rate riders. The rate riders that authorize recovery of unrecovered PRP costs and the deferred PGA include both a recovery of costs and a return on investment during the recovery period. We have two rate riders that authorize the recovery of unrecovered ERC. The ERC rate rider for Atlanta Gas Light only allows for recovery of the costs incurred and the recovery period occurs over the five years after the expense is incurred. ERC associated with the investigation and remediation of Elizabethtown Gas remediation sites located in the state of New Jersey are recovered under a remediation adjustment clause and include the carrying cost on unrecovered amounts not currently in rates.

The regulatory liabilities are refunded to ratepayers through a rate rider or base rates. If the regulatory liability is included in base rates, the amount is reflected as a reduction to the rate base in setting rates.

The ERC liability is included as a corresponding regulatory asset, which is a combination of accrued ERC and unrecovered cash expenditures for investigation and cleanup costs. Atlanta Gas Light has three ways of recovering investigation and cleanup costs. First, the Georgia Commission has approved an ERC recovery rider. The ERC recovery mechanism allows for recovery of expenditures over a five-year period subsequent to the period in which the expenditures are incurred. Atlanta Gas Light expects to collect $29 million in revenues over the next 12 months under the ERC recovery rider, which is reflected as a current asset. The amounts recovered from the ERC recovery rider during the last three years were

- $28 million in 2005
- $25 million in 2004
- $23 million in 2003

The second way to recover costs is by exercising the legal rights Atlanta Gas Light believes it has to recover a share of its costs from other potentially responsible parties, typically former owners or operators of these sites. There were no material recoveries from potentially responsible parties during 2005, 2004 or 2003. The third way to recover costs is from the receipt of net profits from the sale of remediated property. There were no sales of property during 2005.

Elizabethtown Gas In New Jersey, Elizabethtown Gas is currently conducting remediation activities with oversight from the New Jersey Department of Environmental Protection. Although we cannot estimate the actual total cost of future environmental investigation and remediation efforts with precision, based on probabilistic models similar to those used at Atlanta Gas Light's former operating sites, the range of reasonably probable costs is $57 million to $104 million. As of December 31, 2005, no value within this range was a better estimate than any other value, so we have recorded a liability equal to the low end of that range, or $57 million.

Prudently incurred remediation costs for the New Jersey properties have been authorized by the NJBPU to be recoverable in rates through a remediation adjustment clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $63 million, inclusive of interest, as of December 31, 2005, reflecting the future recovery of both incurred costs and accrued carrying charges. Elizabethtown Gas has also been successful in recovering a portion of remediation costs incurred in New Jersey from its insurance carriers and continues to pursue additional recovery.

Sites in North Carolina We also own a former NUI remediation site in Elizabeth City, North Carolina that is subject to a remediation order by the North Carolina Department of Energy and Natural Resources. We currently have only partial information regarding environmental impacts at the Elizabeth City site, and therefore we can make quantitative cost estimates only for limited components of a site cleanup. However, experience at other similar sites suggests that costs for remediation of this site will likely range from $10 million to $17 million. As of December 31, 2005, we have recorded a liability of $10 million related to this site.

There is one other site in North Carolina where investigation and remediation is likely, although no remediation order exists and we do not believe costs associated with this site can be reasonably estimated. In addition, there are as many as six other sites with which NUI had some association, although no basis for liability has been asserted, and accordingly we have not accrued any remediation liability. There are currently no cost recovery mechanisms for the environmental remediation sites in North Carolina.

the option to increase the aggregate principal amount available for borrowing to $1.1 billion on not more than three occasions during each calendar year. The amended Credit Facility expires on August 31, 2010.

SouthStar Line of Credit In April 2004, the SouthStar line of credit was extended to April 2007. This line is collateralized by various percentages of eligible accounts receivable, unbilled revenue and inventory of SouthStar. The base rate on the line is the prime rate and/or LIBOR plus a margin based on certain financial measures. We do not guarantee or provide any other form of security for the repayment of any outstanding indebtedness.

Sequent Line of Credit In June 2005, Sequent's $25 million unsecured line of credit was extended to July 2006. In September 2005, Sequent entered into an additional $20 million unsecured line of credit scheduled to expire in September 2006. These unsecured lines of credit, which total $45 million and bear interest at the federal funds effective rate plus 0.5%, are used solely for the posting of margin deposits for New York Mercantile Exchange transactions and are unconditionally guaranteed by AGL Resources.

Pivotal Utility Holdings Line of Credit In September 2005, Pivotal Utility entered into a $20 million unsecured line of credit expiring on September 30, 2006. This line of credit supports Elizabethtown Gas' hedging program and bears interest at the federal funds effective rate plus 0.5%, is used solely for the posting of deposits and is unconditionally guaranteed by us. For more information on Elizabethtown Gas' hedging program, see Note 4.

Long-term Debt

Our long-term debt matures more than one year from the date of issuance and consists of medium-term notes Series A, Series B and Series C, which we issued under an indenture dated December 1, 1989; senior notes; gas facility revenue bonds; notes payable to Trusts; and capital leases. The notes are unsecured and rank on parity with all our other unsecured indebtedness. Our annual maturities of long-term debt are as follows:

- $4 million in 2007–2010
- $1,611 million in 2011 and beyond

Senior Notes The following table provides more information on our senior notes, which were issued to refinance portions of our existing short-term debt and medium-term notes, to finance acquisitions and for general corporate purposes.

Issue date	Amount (in millions)	Interest rate	Maturity
February 2001	$300	7.125%	January 2011
July 2003	225	4.45	April 2013
September 2004	250	6.0	October 2034
December 2004	200	4.95	January 2015

In March 2003, we entered into interest rate swaps of $100 million to effectively convert a portion of the fixed-rate interest obligation on the $300 million in Senior Notes Due 2011 to a variable-rate obligation. We pay floating interest each January 14 and July 14 at six-month LIBOR plus 3.4%. The effective variable interest rate at December 31, 2005 was 7.2%. These interest rate swaps expire January 14, 2011, unless terminated earlier. For more information on our interest rate swaps, see Note 4.

The trustee with respect to all of the above-referenced senior notes is the Bank of New York Trust Company, N.A. (Bank of New York), pursuant to an indenture dated February 20, 2001. We fully and unconditionally guarantee all our senior notes.

Gas Facility Revenue Bonds Pivotal Utility has $200 million of indebtedness pursuant to gas facility revenue bonds. We do not guarantee or provide any other form of security for the repayment of this indebtedness. Pivotal Utility is party to a series of loan agreements with the New Jersey Economic Development Authority (NJEDA) pursuant to which the NJEDA has issued four series of gas facility revenue bonds:

- $47 million of bonds at adjusting rates due October 1, 2022
- $20 million of bonds at adjusting rates due October 1, 2024
- $39 million of bonds at variable rates due June 1, 2026 (variable bonds)
- $55 million of bonds at 5.7% due June 1, 2032
- $40 million of bonds at 5.25% due November 1, 2033

In April 2005, we refinanced $20 million of our Gas Facility Revenue Bonds Due October 1, 2024. The original bonds had a fixed interest rate of 6.4% per year and were refunded with $20 million of adjustable-rate gas facility revenue bonds. The maturity date of these bonds remains October 1, 2024. The new bonds were issued at an initial annual interest rate of 2.8% and initially have a 35-day auction period where the interest rate will adjust every 35 days. The interest rate at December 31, 2005 was 3.3%.

In May 2005, we refinanced an additional $47 million in Gas Facility Revenue Bonds Due October 1, 2022 and bearing interest at an annual fixed rate of 6.35%. The new bonds were issued at an initial annual interest rate of 2.9% and initially have a 35-day auction period where the interest rate will adjust every 35 days. The maturity date remains October 1, 2022. The interest rate at December 31, 2005 was 3.2%.

The variable bonds contain a provision whereby the holder can "put" the bonds back to the issuer. In 1996, Pivotal Utility executed a long-term Standby Bond Purchase Agreement (SBPA) with a syndicate of banks, which was amended and restated on June 1, 2005. Under the terms of the SBPA, as further amended, the participating banks are obligated under certain circumstances to purchase variable bonds that are tendered by the holders thereof and not remarketed by the remarketing agent. Such obligation of the participating banks would remain in effect until the June 1, 2010 expiration of the SBPA, unless it is extended or earlier terminated.

Notes Payable to Trusts In June 1997, we established AGL Capital Trust I (Trust I), a Delaware business trust, of which AGL Resources owns all the common voting securities. Trust I issued and sold $75 million of 8.17% capital securities (liquidation amount $1,000 per capital security) to certain initial investors. Trust I used the proceeds to purchase 8.17% junior subordinated deferrable interest debentures issued by us. Trust I capital securities are subject to mandatory redemption at the time of the repayment of the junior subordinated debentures on June 1, 2037, or the optional prepayment by us after May 31, 2007.

In March 2001, we established AGL Capital Trust II (Trust II), a Delaware business trust, of which AGL Capital owns all the common voting securities. In May 2001, Trust II issued and sold $150 million of 8.00% capital securities (liquidation amount $25 per capital security). Trust II used the proceeds to purchase 8.00% junior subordinated deferrable interest debentures issued by us. The proceeds from the issuance were used to refinance a portion of our existing short-term debt under the commercial paper program. Trust II capital securities are subject to mandatory redemption at the time of the repayment of the junior subordinated debentures on May 15, 2041, or the optional prepayment by AGL Capital after May 21, 2006. Additionally we entered into interest rate swaps to effectively convert a portion of the fixed-rate interest obligation on our notes payable to Trusts to a variable-rate obligation. At the beginning of 2005, we had $75 million of outstanding interest rate swap agreements associated with our Note Payable at AGL Capital Trust II. On September 7, 2005, we terminated these interest rate swap agreements. We received a payment of $1 million related to this termination, which included accrued interest and the fair value of these interest rate swap agreements at the termination date.

The trustee is the Bank of New York with respect to the 8.17% capital securities pursuant to an indenture dated June 11, 1997, and with respect to the 8.00% capital securities pursuant to an indenture dated May 21, 2001. We fully and unconditionally guarantee all our Trust I and Trust II obligations for the capital securities.

Other Preferred Securities As of December 31, 2005, we had 10 million shares of authorized, unissued Class A junior participating preferred stock, no par value, and 10 million shares of authorized, unissued preferred stock, no par value.

Capital Leases Our capital leases consist primarily of a sale/leaseback transaction completed in 2002 by Florida City Gas related to its gas meters and other equipment and will be repaid over 11 years. Pursuant to the terms of the lease agreement, Florida City Gas is required to insure the leased equipment during the lease term. In addition, at the expiration of the lease term, Florida City Gas has the option to purchase the leased meters from the lessor at their fair market value.

Default Events

Our Credit Facility financial covenants and the PUHCA require us to maintain a ratio of total debt to total capitalization of no greater than 70%. As of December 31, 2005 this ratio was 59%. Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include

- a maximum leverage ratio
- insolvency events and nonpayment of scheduled principal or interest payments
- acceleration of other financial obligations
- change of control provisions

We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that requires us to issue equity based on credit ratings or other trigger events. We are currently in compliance with all existing debt provisions and covenants.

Our four operating segments are now as follows:

- Distribution operations consists primarily of
  - Atlanta Gas Light
  - Chattanooga Gas
  - Elizabethtown Gas
  - Elkton Gas
  - Florida City Gas
  - Virginia Natural Gas
- Retail energy operations consists of SouthStar
- Wholesale services consists of Sequent
- Energy investments consists primarily of
  - AGL Networks, LLC
  - Pivotal Jefferson Island
  - Pivotal Propane

We treat corporate, our fifth segment, as a nonoperating business segment, and it currently includes AGL Resources, AGL Services Company, Pivotal Energy Development and the effect of intercompany eliminations. We eliminated intersegment sales for the years ended December 31, 2005, 2004 and 2003 from our statements of consolidated income.

We evaluate segment performance based primarily on the non-GAAP measure of earnings before interest and taxes (EBIT), which includes the effects of corporate expense allocations. EBIT is a non-GAAP measure that includes operating income, other income, equity in SouthStar's income in 2003, donations, minority interest in 2005 and 2004 and gains on sales of assets. Items that we do not include in EBIT are financing costs, including interest and debt expense, income taxes and the cumulative effect of a change in accounting principle, each of which we evaluate on a consolidated level. We believe EBIT is a useful measurement of our performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations.

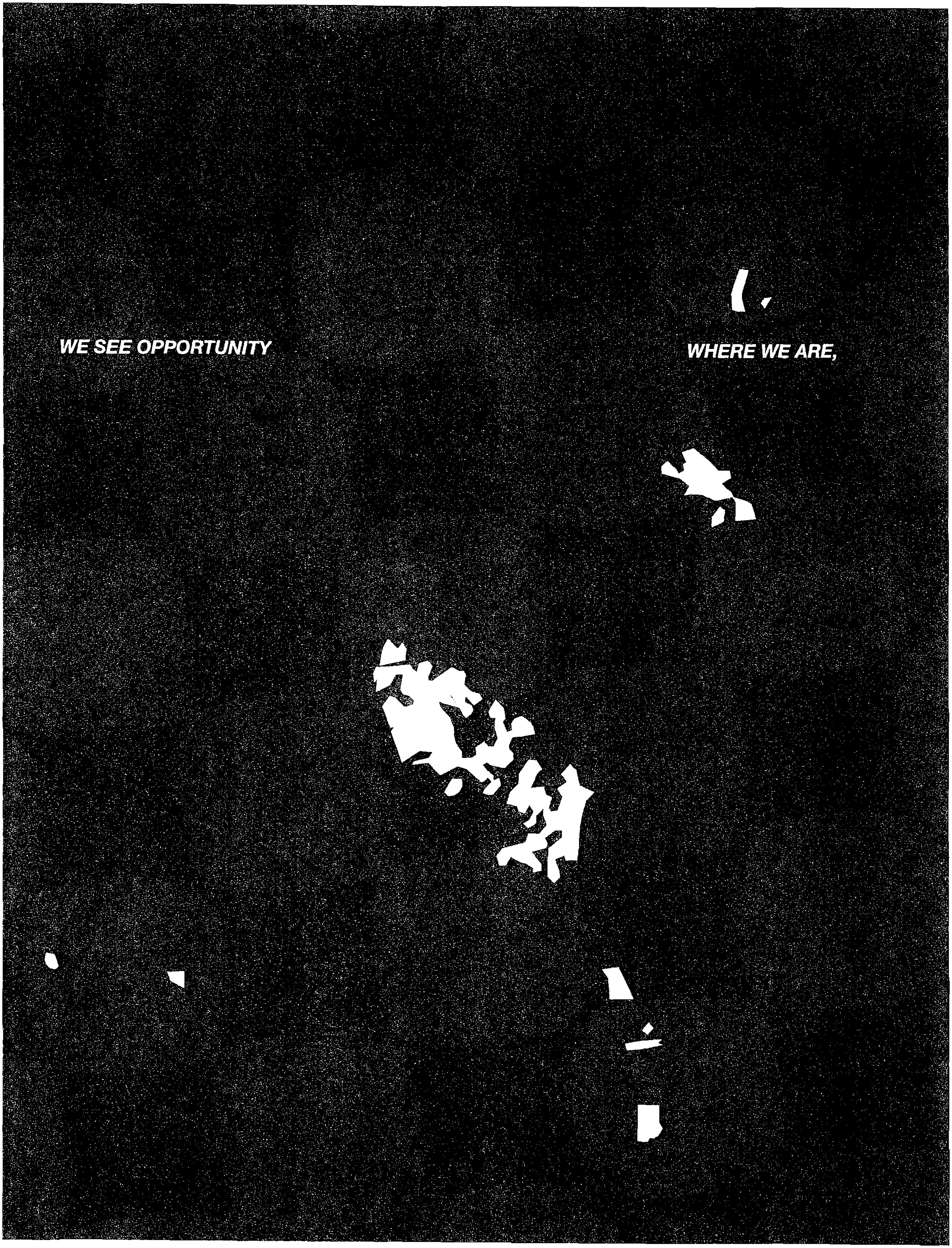
You should not consider EBIT an alternative to, or a more meaningful indicator of our operating performance than, operating income or net income as determined in accordance with GAAP. In addition, our EBIT may not be comparable to a similarly titled measure of another company. The reconciliations of EBIT to operating income and net income for the years ended December 31, 2005, 2004 and 2003 are presented below.

In millions	2005	2004	2003
Operating revenues	**$2,718**	$1,832	$983
Operating expenses	**2,276**	1,500	741
Gain on sale of Caroline Street campus	**—**	—	16
Operating income	**442**	332	258
Other income	**(1)**	—	40
Minority interest	**(22)**	(18)	—
EBIT	**419**	314	298
Interest expense	**109**	71	75
Earnings before income taxes	**310**	243	223
Income taxes	**117**	90	87
Income before cumulative effect of change in accounting principle	**193**	153	136
Cumulative effect of change in accounting principle	**—**	—	(8)
Net income	**$ 193**	$ 153	$128

11

WHAT DO YOU SEE?

AGL RESOURCES INC. 2004 ANNUAL REPORT


WE SEE OPPORTUNITY
WHERE WE ARE,

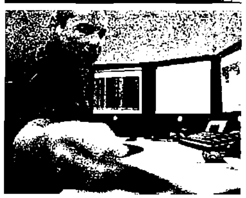
AND WHERE WE CAN BE.

WE SEE DIFFERENTLY.

With our 2004 acquisitions of Jefferson Island Storage & Hub and of NUI Corporation (including several natural gas utilities), AGL Resources is positioned to become the pre-eminent natural gas distributor on the East Coast. These assets, along with the planned 2005 additions of our Pivotal propane plant in Virginia and Macon pipeline expansion, have significantly strengthened our infrastructure portfolio. We now serve 2.2 million retail residential, commercial and industrial customers, plus a substantial portion of large wholesale customers throughout the eastern half of the U.S. Step by step we're building value, and each step brings new fields of opportunity into view.

AGL Resources

AT A GLANCE — 2004



More than 2,900 AGL Resources employees serve our 2.? million customers

DISTRIBUTION OPERATIONS

Atlanta Gas Light is the largest natural gas distribution in the Southeast, serving 237 communities in the state of Georgia. It provides gas delivery service to more than 1.5 million residential, commercial and industrial customers and delivers approximately 238 billion cubic feet of gas annually. It also owns and operates more than 29,000 miles of distribution pipeline and three liquefied natural gas (LNG) plants.

Chattanooga Gas provides retail natural gas sales and transportation services to approximately 60,000 customers in Hamilton County and Bradley County, Tennessee. It delivers approximately 16.7 billion cubic feet of gas annually, and also owns and operates more than 1,400 miles of pipeline and one LNG plant.

Elizabethtown Gas provides natural gas service to approximately 265,000 residential, commercial and industrial customers in northwestern New Jersey. It delivers approximately 60.5 billion cubic feet of gas annually through more than 2,900 miles of distribution pipeline.

Florida City Gas provides natural gas service to approximately 104,000 residential, commercial and industrial customers in southeastern and east central Florida. It delivers approximately 9.5 billion cubic feet of gas annually through more than 6,100 miles of distribution pipeline.

Virginia Natural Gas provides natural gas service to more than 256,000 residential, commercial and industrial customers in southeastern Virginia. It delivers approximately 35 billion cubic feet of gas annually through more than 4,800 miles of distribution pipeline. It also owns and operates a 15-mile high-pressure, large-diameter transmission pipeline serving major wholesale customers.

Service is also provided to 5,900 natural gas customers in Elkton, Maryland by *Elkton Gas* and 300 customers in southwestern Virginia by *Virginia Gas*.

WHOLESALE SERVICES

Sequent Energy Management provides customers in the eastern half of the United States with proven ways to optimize their natural gas asset portfolio and increase cost effectiveness, from wellhead to burner tip. Sequent offers natural gas asset management, producer and storage services, and full-requirements gas supply, including peaking needs.

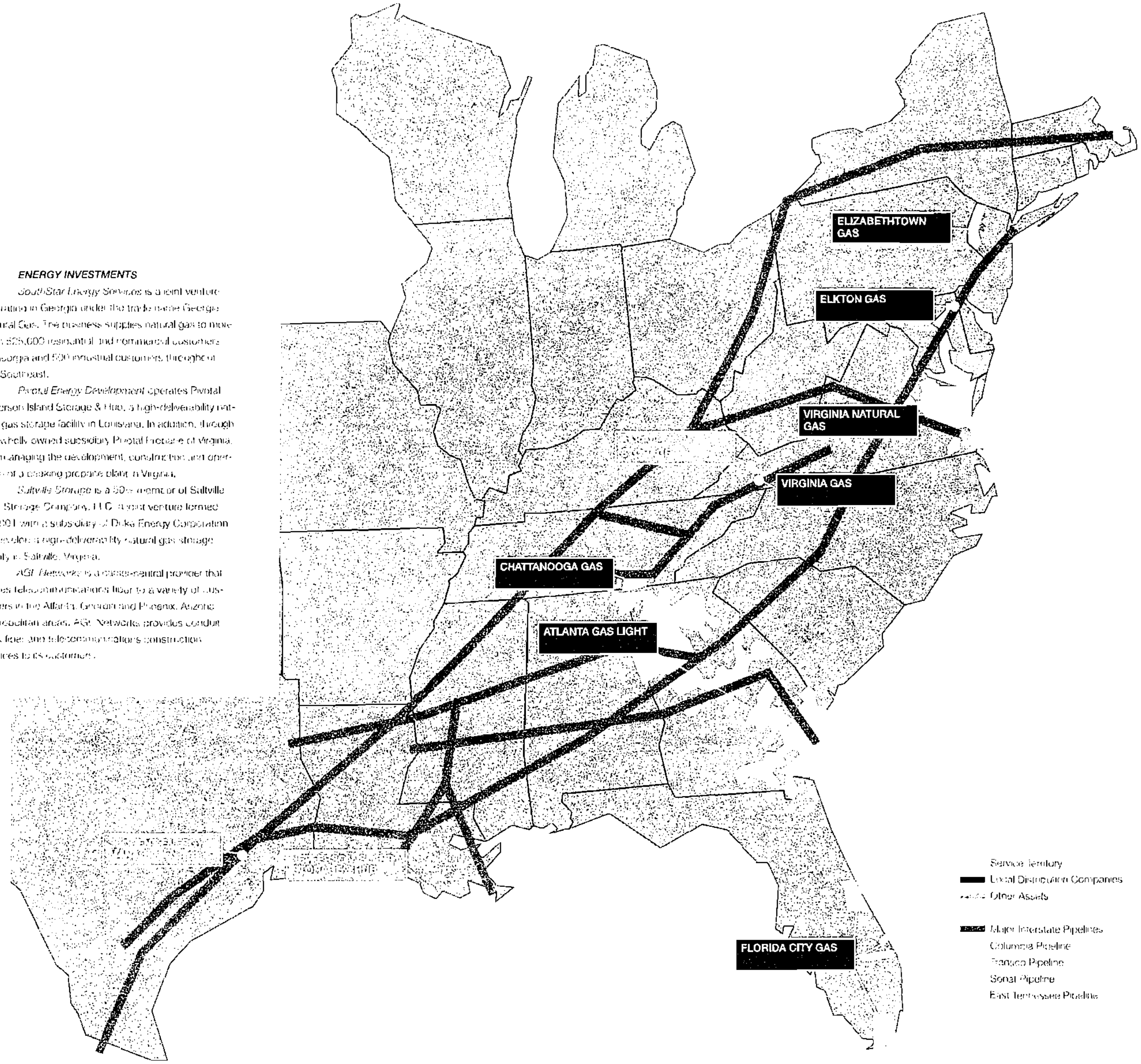
ENERGY INVESTMENTS

SouthStar Energy Services is a joint venture operating in Georgia under the trade name Georgia Natural Gas. The business supplies natural gas to more than 525,000 residential and commercial customers in Georgia and 500 industrial customers throughout the Southeast.

Pivotal Energy Development operates Pivotal Jefferson Island Storage & Hub, a high-deliverability natural gas storage facility in Louisiana. In addition, through our wholly owned subsidiary Pivotal Propane of Virginia, it is managing the development, construction and operation of a peaking propane plant in Virginia.

Saltville Storage is a 50% member of Saltville Gas Storage Company, LLC, a joint venture formed in 2001 with a subsidiary of Duke Energy Corporation to develop a high-deliverability natural gas storage facility in Saltville, Virginia.

AGL Networks is a carrier-neutral provider that leases telecommunications fiber to a variety of customers in the Atlanta, Georgia and Phoenix, Arizona metropolitan areas. AGL Networks provides conduit, dark fiber and telecommunications construction services to its customers.



OUR BUSINESS MAY BE UTILITIES, BUT OUR JOB IS TO CREATE VALUE.

AGL Resources has generated steady, consistent gains for our investors over the past five years. We are an organization with an appetite for achievement that is focused firmly on creating value. Simply put, we never stop searching—and as a result, we find opportunities to create value in places others may dismiss or discount. We understand the power of incremental gains to build meaningful returns. We scan the horizon continually for new opportunities. And the specific assets or projects we select must meet demanding criteria: a favorable purchase price and the ability to add value both quickly and over time.

Our 2004 acquisitions are consistent with this strategy and these criteria, and position us for further incremental growth.

- The purchase of a natural gas storage facility, ideally positioned to support current natural gas storage demand and rising LNG imports, substantially strengthens our infrastructure portfolio.

- Utilities in New Jersey, Florida, Maryland and Virginia, acquired through our purchase of NUI Corporation, offer significant opportunities to use our core capabilities to improve performance for both customers and investors.

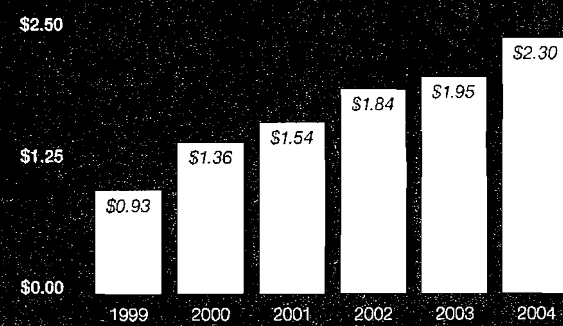
Our team of businesses and individuals is committed to the hard work of building value one step at a time. And as you can see in the charts on page 3, this commitment is paying dividends.

EARNINGS PER SHARE

Basic earnings per share at right exclude the following:

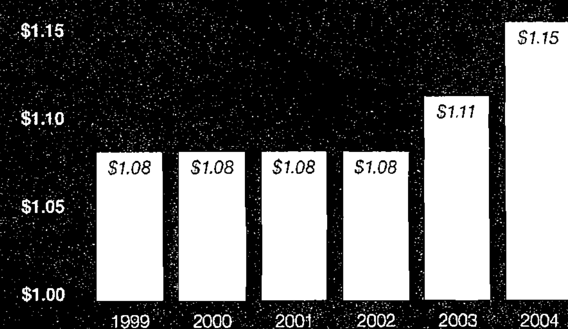
- in 2003, an 8-cent gain on the sale of company property, net of donation of the proceeds to a charitable organization
- in 2001, a 13-cent gain on the sale of a subsidiary
- in 2000, a 4-cent gain on certain items
- in 1999, a 39-cent gain on the sale of joint venture interests

Including these items, basic earnings per share were $2.03 in 2003, $1.67 in 2001, $1.40 in 2000 and $1.32 in 1999.



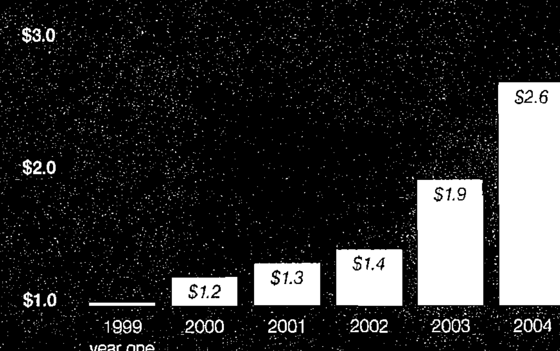
DIVIDEND PER SHARE

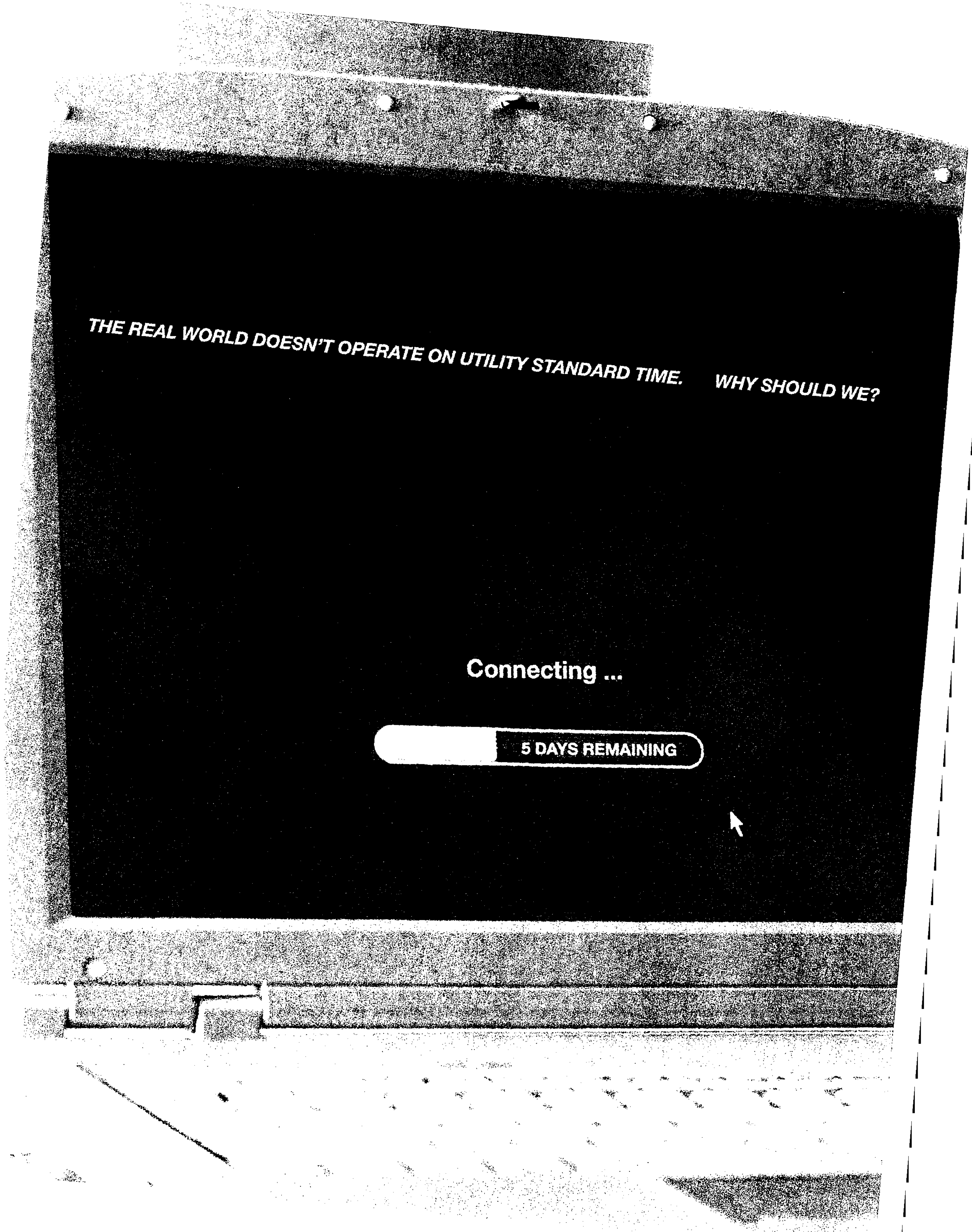
Indicates annual dividend per share paid during the years noted.



MARKET CAPITALIZATION

As of December 31, in billions of dollars.




THE REAL WORLD DOESN'T OPERATE ON UTILITY STANDARD TIME.
WHY SHOULD WE?
Connecting ...
5 DAYS REMAINING

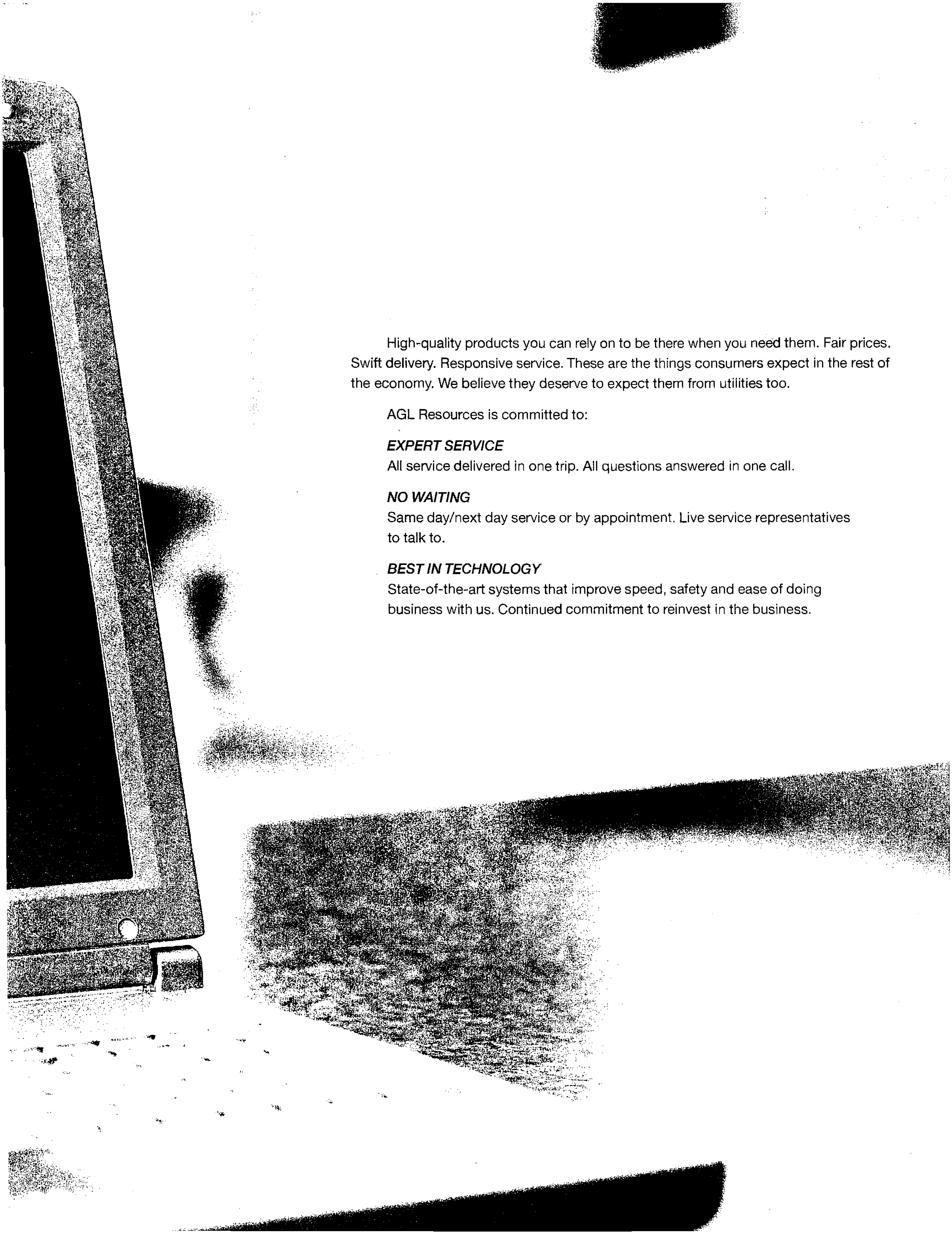
High-quality products you can rely on to be there when you need them. Fair prices. Swift delivery. Responsive service. These are the things consumers expect in the rest of the economy. We believe they deserve to expect them from utilities too.

AGL Resources is committed to:

EXPERT SERVICE
All service delivered in one trip. All questions answered in one call.

NO WAITING
Same day/next day service or by appointment. Live service representatives to talk to.

BEST IN TECHNOLOGY
State-of-the-art systems that improve speed, safety and ease of doing business with us. Continued commitment to reinvest in the business.



When AGL Resources enters a new community, we bring with us four values that guide our business conduct. We will behave with honesty. We will create value. We will be generous in spirit. We will operate inside the lines.

Our job is to work well inside the rules and regulations under which we are required to operate, and not to push the envelope with respect to those rules. Our job is to provide a high-quality product, asking more of ourselves than others do. Our job is to manage the energy assets of our utility franchises to the benefit of customers. Our job is to deliver excellent customer service — because our customers have a choice in meeting their energy needs, and we want them to choose natural gas delivered by our franchises.

We never stop looking for opportunities to improve performance — from reducing the amount of time it takes to turn on, turn off and read meters, to minimizing the amount of time customers spend on the phone arranging for service. That's why we work to identify, develop and integrate new tools and technologies that make us better at what we do. The scale of our operations now makes it easier to drive best practices through our organizations.

The industry-leading operating efficiencies we've developed over the past five years in our distribution companies in Georgia, Tennessee and Virginia have improved service for customers and increased returns for investors. In December 2004, we welcomed 375,000 former NUI customers in New Jersey, Maryland, Virginia and Florida, and we look forward to working just as hard for them.

AGL Resources is dedicated to the idea that every good thing starts with getting it right for our customers. Our aspiration is to develop a national reputation for excellent customer service.

AGL Resources' utility franchises now serve more than 2.2 million customers in six states stretching from Florida to New Jersey. Our operations span every climate zone on the Eastern Seaboard. We deliver more than 350 billion cubic feet of natural gas annually through these franchises, and own and operate more than 41,000 miles of pipeline and five LNG plants.

Our focus will always be the customer. We listen. We follow a "one call, that's all" philosophy in our customer care center, and a "one trip, that's it" practice for meeting customers' expectations in their homes.

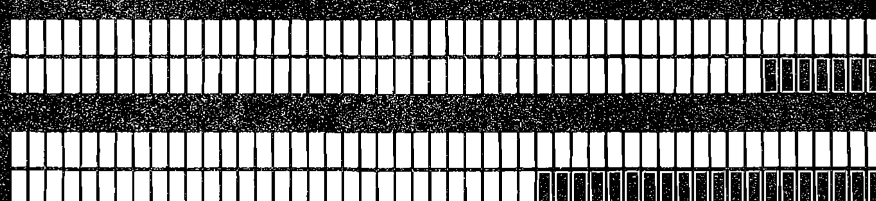
We see a clear opportunity to improve performance and service for our customers in New Jersey and Florida.

2004 CUSTOMER SATISFACTION

AGL Resources' legacy franchises achieved a 93% customer satisfaction rating in 2004, and we're committed to improving that performance. Customer satisfaction ratings for Elizabethtown Gas and Florida City Gas measured 80% for the same period.

Atlanta Gas Light, Virginia Natural Gas, Chattanooga Gas

Elizabethtown Gas, Florida City Gas

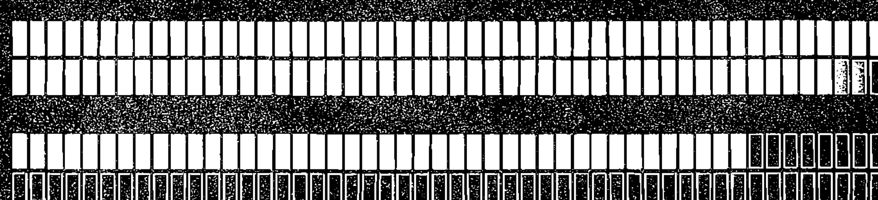


2004 METER READING

Bill accuracy depends heavily on monthly meter reading. AGL Resources' legacy franchises read close to 100% of meters each month in 2004. Elizabethtown and Florida City Gas read only 42% of customer meters.

Atlanta Gas Light, Virginia Natural Gas, Chattanooga Gas

Elizabethtown Gas, Florida City Gas




WE SEE WINTE

As our natural gas distribution business continues to expand, it is more important than ever to invest in strategic assets that provide significant flexibility and the opportunity to offer dependable service to all our customers. In 2004, we took several steps to protect reliable and economical delivery of natural gas.

Peaking assets are more important than ever before in the energy industry. While natural gas usage per customer has remained relatively flat or declined, the way in which this gas is consumed has changed as appliances and homes become more energy efficient. In particular, weather drives the use of natural gas — which means more assets are needed to meet peak demand but for fewer days per year. The challenge for suppliers and gas utilities is to create a portfolio of assets that will serve this growing peak demand without forcing the customer to pay unnecessary fixed costs for resources.

Recognition of the need for peaking capacity, coupled with our concerns about the ability of major pipeline companies to make the capital investments necessary to meet peak demands, led us to move quickly on two projects to ensure system reliability and high-quality service to customers. In Virginia, our construction of a propane-air peaking plant will reduce our dependence on major interstate pipelines for critical supply during the coldest days of the year. In Georgia, we agreed to acquire 250 miles of interstate pipeline serving the Macon-to-Atlanta corridor. This purchase will save customers money by improving access to one of our LNG facilities and by enhancing the overall reliability of our Georgia distribution system.

Acquisition of the Jefferson Island facility adds substantial natural gas storage capacity to our infrastructure portfolio, and positions us for an even stronger future through the facility's expansion potential. Located on the Gulf Coast, the two salt dome gas storage caverns are connected to six major interstate pipelines via the Henry Hub. Jefferson Island creates the opportunity for an additional income stream by enhancing our ability to provide custom-tailored services to energy clients throughout the eastern United States. Capacity can be expanded economically when market conditions and operating parameters warrant.

Even as we develop and acquire new assets, we will continue to optimize the assets we already own. Sequent Energy Management's wholesale marketing and asset management services continue to enhance results for our utility franchises, and for other energy clients east of the Rockies. In 2004, Sequent's asset optimization activities returned $1.3 million to Chattanooga Gas customers, $3.0 million to Virginia Natural Gas customers and $3.8 million to Georgia's Universal Service Fund. Sequent will supply asset management services to Elizabethtown Gas in New Jersey beginning in April 2005. We expect its client list will continue to grow as Sequent gains increased recognition for its ability to reduce costs and build value for its customers.

FOR THE FOURTH YEAR IN A ROW, WE PRODUCED RECORD RESULTS.

RECORD EARNINGS PER SHARE $2.30

RECORD SHARE PRICE $33.59

RECORD ANNUAL DECLARED DIVIDEND $1.16 PER SHARE

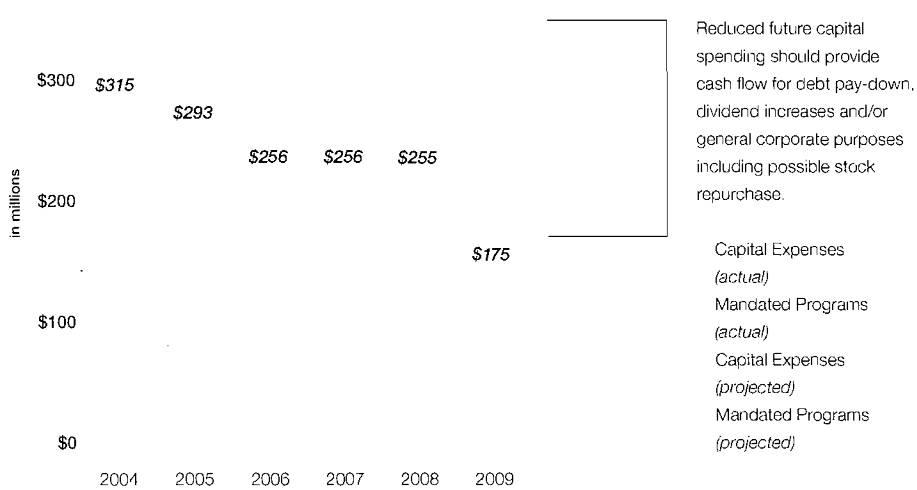
RECORD EQUITY MARKET CAPITALIZATION $2.6 BILLION

In 2004, AGL Resources dividends combined with earnings growth per share produced a 19% total return to shareholders. Our value proposition for value-oriented investors remains the same: to produce sustainable earnings and a substantial dividend — with an element of growth. Our goals remain realistic: to deliver consistent returns in the 8% to 12% range. A clear line of sight to EPS growth in 2005 should keep us on track to achieve this goal in the coming year. Our dividend was increased to $1.16 per share by the Board of Directors in April 2004 and to $1.24 per share in February 2005. Our payout ratio for 2004 was 50%, which remains among the lowest of our peer group, supporting our dividend and allowing room for future growth.

OUR LONG-TERM VALUE PROPOSITION	Target	Actual
	4–6% Year-to-year earnings per share growth	EPS growth from 2000–2004 has averaged 14%.
	4–6% Competitive dividend yield	Dividend yield ranged from 3.5% to 4.3% during 2004.

We continued to focus on the strength of our balance sheet in 2004 by prudently capitalizing our acquisition of NUI and Jefferson Island Storage & Hub. We kept a close eye on our debt-to-total-capitalization ratio, overall cost of debt, liquidity position and interest coverage ratios. In November 2004, we issued 11 million shares of common stock raising $332 million to fund our 2004 acquisitions. We continue to execute on our strategy to buy assets economically that will add value in the near term as well as the long term. These new assets will provide additional opportunities to replicate our operational excellence model in new franchise territories and across a larger asset base.

Maintaining a strong balance sheet and adding new sources of incremental earnings are important steps toward improving cash flow and unlocking potential value for shareholders. Our cash flow picture also will be enhanced going forward by reduced spending over time related to two mandated regulatory programs — environmental cleanup and pipeline replacement. This improved cash flow position in succeeding years will place us in a better position than ever before to create sustainable value for shareholders.



TO OUR SHAREHOLDERS

Last year, I promised that in 2004 AGL Resources would continue to create value through a measured pace, a commitment to running the business for quality and for the long term, and a dividend strategy that rewards the patient investor. In the last 12 months, we have run our base business to provide strong earnings growth, earning a record $2.30 per share. We have expanded our utility business to three new states (New Jersey, Florida and Maryland). We have become the largest gas distributor in the eastern U.S. with 2.2 million customers; and with an equity market capitalization of $2.6 billion, we have become the largest of the pure gas distribution companies. We have expanded our asset mix through the accretive acquisition of Pivotal Jefferson Island Storage & Hub in Louisiana. We are in the process of constructing a new propane plant in Virginia and will shortly close on the acquisition of 250 miles of pipeline from Southern Natural Gas, an affiliate of El Paso Corporation, to reconfigure our infrastructure in Georgia. The Board of Directors raised our annual dividend twice in the last 12 months: in April 2004 by $0.04 per share and in February 2005 by $0.08 per share. Our annual dividend now stands at $1.24 per share.

PAULA ROSPUT REYNOLDS Chairman, President and Chief Executive Officer

The performance on our commitment can perhaps best be viewed in the following way. The chart below illustrates the total return to shareholders (share price appreciation plus dividend) for the several years that our management team has been in place. These have been years of steady improvement, and 2004 has been a particularly noteworthy one. I hope you will agree that we have delivered on our goal to provide value to you.

We thank you for the opportunity to be stewards of your investment and for your continued confidence in our strategic direction.

WHAT DO YOU SEE?

This year's report asks, "What Do You See?" Despite the fact that the demand for our product, natural gas, grows only modestly, I see a world of possibilities in store for our company. This optimism is not merely a frame of mind, but is based on certain fundamentals about the business. I've listed them below, with a short explanation of each that gives some context to our 2005 goals.

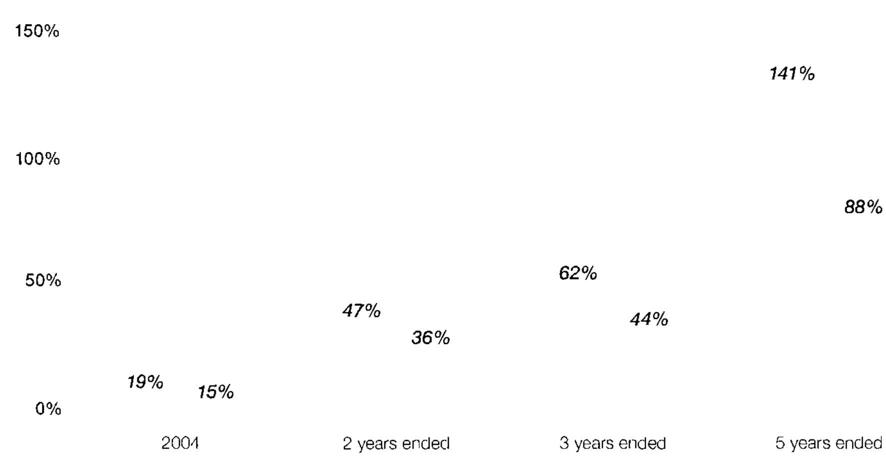
There is always room for improvement. Even though most of our operating and financial metrics (e.g., cost/customer, customers/employee, cost/new meter, EBIT/customer) are in the first quartile of industry benchmarks, there are many additional technology and business process improvements we can adopt to raise our performance. These include rollout of global positioning systems in all our vehicles; work management software to automate the flow of marketing, design, construction and maintenance of our facilities; use of our enterprise resource program to retire obsolete business systems of newly acquired utilities; and full deployment of our energy trading and risk management system in our asset management and retail marketing businesses. These platforms are generally not new. Rather, they are proven systems in use in general industry. Our goal must not be to settle for doing what other utilities do. Instead, we must adopt the business practices and systems used by leading-edge companies in the global economy.

Volatility in gas markets is not transitory. After several years of intensive drilling all over North America, most experts have concluded that there are limits to our geology and hence to the amount of deliverability we can attain at historical prices.

HISTORICAL TOTAL RETURN

AGL Resources
Price Appreciation
Dividend Yield

Peers
Price Appreciation
Dividend Yield



As a nation, we are thrust into global energy markets in the competition for supplemental supplies – mainly in the form of liquefied natural gas (LNG). Availability and pricing of these cargoes will be irregular, at least until the worldwide market for LNG matures. Thus we can expect volatility in U.S. gas prices for some time to come. Consequently, we must develop plans to diversify our supplies, stabilize our rates, and realign our pipelines and contracts to reflect the new realities. But from a shareholder growth and value standpoint, volatility supports the profitability of our asset management business. Volatility also provides assurance that there will be demand for the wholesale storage capacity we own and operate – capacity that we intend to enhance and expand at Jefferson Island.

Peak demand grows significantly more quickly than average demand.

Despite record home ownership in our nation and record housing starts in our service territories, the demand for natural gas has grown only modestly. Even with multiple gas end uses in homes today, the quality of construction and more efficient appliances moderate demand. But on the coldest days of the year, demand is growing significantly faster than average use – two to three to five times faster, depending on the service territory. Peak demand grows more quickly because at extreme temperatures, gas use intensifies, regardless of appliance efficiency. Because large interstate pipelines do not specialize in meeting peak-day requirements, we must identify supplemental resources to meet the 10 to 20 coldest days of the year. This is why our Pivotal propane project is so important in Virginia and why we are expanding and reconfiguring the operations of our Macon, Georgia LNG plant. These facilities provide cost-effective peaking service. Moreover, they are good, solid investments as well.

We won't pay too much to expand our business through acquisition.

Two years ago, I wrote that AGL Resources had gained a reputation for the deals we hadn't done rather than the ones we did do. Dick O'Brien, our chief financial officer, and I have had numerous discussions about the combination of valuation and cost savings that would provide meaningful new earnings for our shareholders. We walked away from a number of opportunities in the intervening period. But this year, the alignment of valuation and synergies manifested itself and we purchased both NUI and Jefferson Island at competitive valuations. In each case, we have work to do to make them best in class, but we also have a clear line of sight to earnings from these investments. Investors obviously agree, as we were able to issue $332 million in equity to finance these acquisitions without any adverse effect on the prevailing share price or any anticipation of earnings dilution.

WHAT WILL YOU SEE IN 2005?

First, *we will integrate our new assets decisively,* driving the inherent value we identified in them to our bottom line. We will simultaneously seek to improve all our business metrics in our pre-existing businesses as well.

Second, with our enlarged business platform, *we intend to earn a national reputation for customer service excellence.* Providing a superior customer experience is part of what sets great companies apart. When gas customers think of great service, we want them to think of our companies. We will work actively to introduce service standards in New Jersey and Florida as well as continue their refinement in other states.

Third, *we will accelerate the pace at which we implement new technology* to achieve our "one company – one way" vision. Standardized business practices promote scalability and efficiency and reduce operating risk. Standardization runs contrary to individualized operating practices – and we reject the latter paradigm as part of the legacy of a fragmented industry.

Fourth, *we will achieve industry-leading levels of disclosure, transparency and collaboration with regulators* in the states in which we serve. In the wake of corporate scandals, we have seen how quickly trust can diminish. We want to be the kind of company that regulators would choose if they could, based on open books and records and solid operating performance. We can only do this through constant engagement and by voluntarily submitting to scrutiny, transparency and measurement against objective standards. We are fortunate to operate in positive regulatory climates, with responsive policymakers. Nevertheless, in various proceedings this year, you will see us redouble our efforts to earn the right to provide comprehensive service in our franchise areas.

WHAT WILL YOU SEE?

Some of our investors have asked us when we will run out of opportunities. The answer is not any time soon. As we tell our team, there is no end game here. There is no destination which, upon reaching it, we can say, "we're here, now we're done." The ethos of a competitive global economy forces us to keep looking for opportunities, to perform better with each passing year and to continue to innovate — for our customers and for our shareholders. 2005 should be an interesting year. Stay with us on the journey. We think you'll like what you see.

Paula Rosput Reynolds

Paula Rosput Reynolds
Chairman, President and Chief Executive Officer
AGL Resources Inc.
March 3, 2005

2005 GOALS

Integrate our acquisitions and meet the performance expectations of our value-oriented investors.

Establish a national reputation for excellent customer service by investing in systems, processes and people.

Accelerate the pace of technology adoption and business process improvement to achieve our "one company" vision.

Elevate our public policy profile with leading levels of transparency and collaboration to facilitate the adoption of our regulatory and business framework.

FINANCIALS

SELECTED FINANCIAL DATA

Selected financial data about us is set forth in the table below. We derived the data in the tables from our audited financial statements. You should read the data in the table in conjunction with our consolidated financial statements and related notes. On September 30, 2001, our Board of Directors elected to change our fiscal year end from September 30 to December 31, effective October 1, 2001. We refer to the three months ended December 31, 2001 as the "Transition Period" in the table below.

We acquired Jefferson Island Storage & Hub, LLC (Jefferson Island) on October 1, 2004, and NUI Corporation (NUI) on November 30, 2004. As a result, our results of operations for 2004 include three months of the acquired operations of Jefferson Island and one month of the acquired operations of NUI. Pursuant to FIN 46R, which we adopted in January 2004, we consolidated all of SouthStar's accounts with our subsidiaries' accounts as of January 1, 2004.

Dollars and shares in millions, except per share amounts	**2004**	2003	2002	Transition Period	2001	2000
Income statement						
Operating revenues	**$1,832**	$ 983	$ 877	$ 204	$ 946	$ 608
Operating expenses						
Cost of gas	**994**	339	268	49	327	112
Operation and maintenance	**377**	283	274	68	267	248
Depreciation and amortization	**99**	91	89	23	100	83
Taxes other than income taxes	**30**	28	29	6	33	27
Total operating expenses	**1,500**	741	660	146	727	470
Gain on sale of Caroline Street campus	**—**	16	—	—	—	—
Operating income	**332**	258	217	58	219	138
Equity in earnings of SouthStar	**—**	46	27	4	14	6
Gain on sale of Utilipro Inc.	**—**	—	—	—	11	—
Gain on propane transaction	**—**	—	—	—	—	13
Other income (loss)	**—**	2	3	1	(7)	9
Donation to private foundation	**—**	(8)	—	—	—	—
Minority interest	**(18)**	—	—	—	—	—
Interest expense	**(71)**	(75)	(86)	(24)	(98)	(58)
Earnings before income taxes	**243**	223	161	39	139	108
Income taxes	**90**	87	58	14	50	37
Income before cumulative effect of change in accounting principle	**153**	136	103	25	89	71
Cumulative effect of change in accounting principle, net of $5 in income taxes	**—**	(8)	—	—	—	—
Net income	**$ 153**	$ 128	$ 103	$ 25	$ 89	$ 71
Common stock data						
Weighted average shares outstanding — basic	**66.3**	63.1	56.1	55.3	54.5	55.2
Weighted average shares outstanding — fully diluted	**67.0**	63.7	56.6	55.6	54.9	55.2
Earnings per share — basic	**$ 2.30**	$ 2.03	$ 1.84	$ 0.45	$ 1.63	$ 1.29
Earnings per share — fully diluted	**$ 2.28**	$ 2.01	$ 1.82	$ 0.45	$ 1.62	$ 1.29
Dividends per share	**$ 1.15**	$ 1.11	$ 1.08	$ 0.27	$ 1.08	$ 1.08
Dividend payout ratio	**50%**	55%	59%	60%	66%	84%
Book value per share[1,2]	**$18.04**	$14.66	$12.52	$12.41	$12.20	$11.49
Market value per share[1]	**$33.24**	$29.10	$24.30	$23.02	$19.97	$20.08
Balance sheet data[1]						
Total assets	**$5,640**	$3,972	$3,742	$3,454	$3,368	$2,588
Long-term liabilities and deferred credits	**682**	647	702	671	711	768
Capitalization						
Long-term debt (excluding current portion)	**1,623**	956	994	1,015	1,065	664
Common shareholders' equity	**1,385**	945	710	690	671	621
Total capitalization	**$3,008**	$1,901	$1,704	$1,705	$1,736	$1,285
Financial ratios[1]						
Capitalization						
Long-term debt	**54%**	50%	58%	60%	61%	52%
Common shareholders' equity	**46**	50	42	40	39	48
Total	**100%**	100%	100%	100%	100%	100%
Return on average common shareholders' equity	**13.1%**	15.5%	14.7%	14.6%	13.8%	11.1%

[1] As of the last day of the respective fiscal period. [2] Common shareholders' equity divided by total outstanding common shares.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Unless the context requires otherwise, references to "we," "us," "our" or the "company" are intended to mean consolidated AGL Resources Inc. and its subsidiaries (AGL Resources). Certain expectations and projections regarding our future performance referenced in this "Management's Discussion and Analysis of Financial Condition and Results of Operations" section and elsewhere in this report, as well as in other reports and proxy statements we file with the Securities and Exchange Commission (SEC), are forward-looking statements. Officers may also make verbal statements to analysts, investors, regulators, the media and others that are forward-looking.

Forward-looking statements involve matters that are not historical facts, such as projections of our financial performance, management's goals and strategies for our business and assumptions regarding the foregoing. Because these statements involve anticipated events or conditions, forward-looking statements often include words such as "anticipate," "assume," "can," "could," "estimate," "expect," "forecast," "indicate," "intend," "may," "plan," "predict," "project," "seek," "should," "target," "will," "would" or similar expressions. For example, in this "Management's Discussion and Analysis of Financial Condition and Results of Operations" section and elsewhere in this report, we have forward-looking statements regarding our expectations for

- revenue growth
- operating income growth
- cash flows from operations
- operating expense growth
- capital expenditures
- our business strategies and goals
- our potential for growth and profitability
- our ability to integrate our recent and future acquisitions
- trends in our business and industries
- developments in accounting standards

Do not unduly rely on forward-looking statements. They represent our expectations about the future and are not guarantees. Our expectations are based on currently available competitive, financial and economic data along with our operating plans. While we believe that our expectations are reasonable in view of the currently available information, our expectations are subject to future events, risks and uncertainties, and there are several factors – many beyond our control – that could cause results to differ significantly from our expectations. We caution readers that, in addition to the important factors described elsewhere in this report, the factors set forth in "Risk Factors," among others, could cause our business, results of operations or financial condition in 2005 and thereafter to differ significantly from those expressed in any forward-looking statements. There also may be other factors not described in this report that could cause results to differ significantly from our expectations.

Forward-looking statements are only as of the date they are made, and we do not undertake any obligation to update these statements to reflect subsequent changes.

OVERVIEW

NATURE OF OUR BUSINESS

We are an energy services holding company whose principal business is the distribution of natural gas in six states – Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. Our six utilities serve more than 2.2 million end-use customers, making us the largest distributor of natural gas in the eastern United States based on number of customers. We are also involved in various related businesses, including retail natural gas marketing to end-use customers in Georgia; natural gas asset management and related logistics activities for our own utilities as well as for other nonaffiliated companies; natural gas storage arbitrage and related activities; operation of high-deliverability underground natural gas storage; and construction and operation of telecommunications conduit and fiber infrastructure within select metropolitan areas. We manage these businesses through three operating segments – distribution operations, wholesale services and energy investments – and a nonoperating corporate segment.

The distribution operations segment is the largest component of our business and is comprehensively regulated by regulatory agencies in six states. These agencies approve rates that are designed to provide us the opportunity to generate revenues; to recover the cost of natural gas delivered to our customers and our fixed and variable costs such as depreciation, interest, maintenance and overhead costs; and to earn a reasonable return for our shareholders. With the exception of Atlanta Gas Light Company (Atlanta Gas Light), our largest utility franchise, the earnings of our regulated utilities are weather-sensitive to varying degrees. Although various regulatory mechanisms provide a reasonable opportunity to recover our fixed costs regardless of volumes sold, the effect of weather manifests itself in terms of higher earnings during periods of colder weather and lower earnings with warmer weather. Our Georgia retail marketing business, SouthStar Energy Services LLC (SouthStar), also is weather-sensitive, and uses a variety of hedging strategies to mitigate potential weather impacts. All of our utilities and SouthStar face competition in the residential and commercial customer markets based on customer preferences for natural gas compared with other energy products and the price of those products relative to that of natural gas.

We derived approximately 96% of our earnings before interest and taxes (EBIT) during the year ended December 31, 2004 from our regulated natural gas distribution business and from the sale of natural gas to end-use customers in Georgia by SouthStar, which is part of our energy investments segment. This statistic is significant because it represents the portion of our earnings that results directly from the underlying business of supplying natural gas to retail customers. Although SouthStar is not subject to the same regulatory framework as our utilities, it is an integral part of the retail framework for providing gas service to end-use customers in the state of Georgia. For more information regarding our measurement of EBIT and the items it excludes from operating income and net income, see "Results of Operations—AGL Resources."

The remaining 4% of our EBIT was principally derived from businesses that are complementary to our natural gas distribution business. We engage in natural gas asset management and operation of high-deliverability natural gas underground storage as adjunct activities to our utility franchises. These businesses allow us to be opportunistic in capturing incremental value at wholesale, provide us with deepened business insight about natural gas market dynamics and facilitate our ability, in the case of asset management, to provide transparency to regulators as to how that value can be captured to benefit our utility customers through sharing arrangements. Given the volatile and changing nature of the natural gas resource base in North America and globally, we believe that participation in these related businesses strengthens our business vitality.

OUR COMPETITIVE STRENGTHS

We believe our competitive strengths have enabled us to grow our business profitably and create significant shareholder value. These strengths include:

Regulated distribution assets located in growing geographic regions

Our operations are primarily concentrated along the east coast of the United States, from Florida to New Jersey. We operate primarily urban utility franchises in growing metropolitan areas where we can deploy technology to improve service delivery and manage costs. We believe the population growth and resulting expansion in business and construction activity in many of the areas we serve should result in increased demand for natural gas and related infrastructure for the foreseeable future.

Demonstrated track record of performance through superior execution

We continue to focus our efforts on generating significant incremental earnings improvements from each of our businesses. We have been successful in achieving this goal in the past through a combination of business growth and controlling or reducing our operating expenses. We achieved these improvements to our operations in part through the implementation of best practices in our businesses, including increased investments in enterprise technology, workforce automation and business process modernization.

Proven ability to acquire and integrate natural gas assets that add significant incremental earnings

We take a disciplined approach to identifying strategic natural gas assets that support our long-term business plan. For example, our November 2004 purchase of NUI Corporation (NUI), a New Jersey–based energy holding company with natural gas distribution operations in New Jersey, Florida, Maryland and Virginia, provides us an opportunity to leverage and strengthen one of our core competencies—the efficient, low-cost operation of urban natural gas franchises. The disparity between NUI's pre-acquisition utility operating metrics and cost structure and those of our other utilities provides us an opportunity to achieve significant improvements in NUI's business in 2005 and beyond. In addition, our acquisition in October 2004 of the natural gas storage assets of Jefferson Island Storage & Hub, LLC (Jefferson Island), as discussed below, added immediate incremental earnings to our business and, given the possibilities for expansion, should provide a stable earnings stream going forward.

BUSINESS ACCOMPLISHMENTS IN 2004

- We increased net income 20% to $153 million and fully diluted earnings per share 13% to $2.28 from prior-year amounts. In addition to improvements in our base distribution business and energy investments businesses, we were able to capture additional incremental net income in the wholesale natural gas market through our Sequent Energy Management, L.P. (Sequent) asset management, producer services and storage arbitrage activities.
- We strengthened our position as a leading operator of natural gas utility assets in the eastern United States by acquiring NUI.

- We acquired Jefferson Island, a high-deliverability salt dome gas storage facility in Louisiana, which allows us to migrate into the wholesale market and capitalize on the growing market of utility and large industrial customers, producers, financial intermediaries and marketers who compete to hold firm capacity rights to store natural gas. For more information on our acquisitions on NUI and Jefferson Island, see Note 2.
- We announced our plan to acquire 250 miles of intrastate pipeline in our Georgia service area from Southern Natural Gas (Southern Natural), a subsidiary of El Paso Corporation, which should close in the second quarter of 2005. We expect this acquisition to allow us to, over time, undertake economical reconfiguration of our Georgia transmission grid, integrating gas flows from the Gulf Coast, imported liquefied natural gas (LNG) and our own market-area LNG.
- We began construction of a propane-air facility in Virginia that will provide needed peak-day demand protection for the customers of our Virginia Natural Gas, Inc. (Virginia Natural Gas) utility.
- We continued to support a strong balance sheet by issuing 11.04 million shares of AGL Resources common stock in November 2004, raising net proceeds of $332 million primarily to fund the NUI and Jefferson Island acquisitions.
- We increased our dividend 7% for the third consecutive year. If the current amount per quarter of $0.31 per share is in effect for all of 2005, our indicated annual rate would be $1.24 per share.

AREAS OF STRATEGIC FOCUS IN 2005

Our business strategy is focused on effectively managing our gas distribution operations; optimizing our return on our assets; selectively growing our gas distribution businesses through acquisitions; and developing our portfolio of closely related, unregulated businesses with an emphasis on risk management and earnings visibility. Key elements of our strategy include:

Enhance the value and growth potential of our regulated utility operations

We will seek to enhance the value and growth of our existing utility assets by managing our capital spending effectively; pursuing customer growth opportunities in each of our service areas; establishing a national reputation for excellent customer service by investing in systems, processes and people; working to achieve authorized returns in each jurisdiction and, in those jurisdictions where we have performance-based rates, sharing the benefits with our customers; and maintaining earnings and rate stability through regulatory compacts that fairly balance the interests of customers and shareholders.

Rapidly integrate the NUI assets and achieve the resulting strategic benefits

We are working to integrate NUI's assets into our portfolio of businesses and to provide the associated benefits to our customers and shareholders. Our integration plan includes applying enterprise-wide technology solutions and business processes that are designed to improve the key business metrics we track on a regular basis and bringing NUI's operations to a level of operational and service efficiency comparable to that of our other utility businesses. As part of this process, we also will evaluate certain NUI businesses for possible divestiture, consistent with our philosophy of exiting businesses that do not support our long-term strategy.

Focus on maintaining strong, investment-grade profile and high level of liquidity

We will continue to maintain a disciplined approach to capital spending and improving operating margins to optimize cash flow generation. Additionally, we seek to reduce in the near term our ratio of total debt to total capitalization in order to strengthen our balance sheet and allow us to respond to the capital needs of our operating businesses. We understand the importance of maintaining strong, investment-grade credit ratings in order to support our operating and investment needs, and we intend to execute our strategy in a way that enhances our ability to maintain or improve those ratings.

Achieve appropriate regulatory outcomes that support stable utility earnings

We currently are involved in regulatory proceedings in Georgia and Tennessee. In Georgia, Atlanta Gas Light's rate case is in process and expected to be completed by April 30, 2005. In Tennessee, we anticipate receiving a final ruling on our appeal of a 2004 Chattanooga Gas Company (Chattanooga Gas) rate case in the first quarter. Achieving favorable outcomes in these cases, and any other formal or informal regulatory proceedings in which we may be involved, is integral to the achievement of our earnings targets.

Selectively evaluate the acquisition of natural gas assets

We will selectively examine and evaluate the acquisition of natural gas distribution, gas pipeline or other gas-related assets. Our acquisition criteria include the ability to generate operational synergies, strategic fit relative to our core competencies, value from near-term earnings contributions and adequate returns on invested capital, while maintaining or improving our investment-grade credit ratings.

Selectively expand our other energy businesses
We intend to continue to expand our wholesale services and natural gas storage businesses to provide disciplined incremental earnings growth for shareholders. Sequent intends to continue providing credits to our utility customers through effective management of our affiliated utility assets. In our asset management business, we intend to grow our business with nonaffiliated third parties, as well as the services we provide to our affiliated utilities, by providing producers with markets for their gas commodity; providing end-users with gas supply, storage and asset management options; and arbitraging pipeline and storage assets across various gas markets and time horizons. However, we intend to continue protecting our earnings-at-risk by maintaining our commitment to limited open-position and credit risks and by providing transparency and visibility to regulators under our asset management agreements. As our portfolio of assets and our ability to store more physical gas inventory grow, the volatility of reported earnings from this business may increase. In our high-deliverability underground storage business, we will seek to expand the operating capabilities of our existing facilities to provide more flexible and valuable injection and withdrawal capabilities for our customers. Pivotal Jefferson Island Storage & Hub LLC (Pivotal Jefferson Island) is currently expanding its compression capabilities to increase the number of times a customer can inject and withdraw natural gas. We will complete and begin operation of our propane peaking facility, and look for additional opportunities to provide economical peaking services in the regions in which our utilities operate.

Acquire and retain natural gas customers
We continue to focus significant efforts in our distribution operations business on improving our net customer growth trends, despite the industry-wide challenges of rising prices for natural gas and competition from alternative fuels, declining natural gas usage per customer and declining regional load factors. In each of our utility service areas, we will continue to implement programs aimed at emphasizing natural gas as the fuel of choice for customers and maximizing the use of natural gas through a variety of promotional opportunities. We also are focused on similar customer growth initiatives in our SouthStar retail marketing business in Georgia. In addition, we continue to improve the credit quality of our customers in the retail marketing business and will use those techniques to improve credit and collections activities within our regulated utilities.

Continue to improve revenue and cash flow stability
We have taken a number of actions in recent years to promote more stable and predictable revenues and cash flows in each of our business segments, as well as to moderate the effects of variable factors, such as weather and natural gas prices on our business results. Some of the improvements we have initiated include performance-based ratemaking treatment in Georgia; weather normalization adjustment programs in Virginia and Tennessee; more efficient cost management and cash recovery from our environmental response cost (ERC) program in Georgia; and reduced credit losses from our retail marketing business. We estimate that in 2005 our spending for property, plant and equipment will be $276 million compared to $264 million in 2004. Our capital expenditures should decrease in successive years by reduced spending related to the pipeline replacement program (PRP), a mandated regulatory program that has required significant expenditures. We expect to improve our net cash flow, which should provide enhanced financial flexibility around business investment opportunities and potentially a return of capital to investors to provide additional shareholder value.

REGULATORY ENVIRONMENT

We are subject to the rate regulation and accounting requirements of various state and federal regulatory agencies in the jurisdictions in which we do business. We are committed to working cooperatively and constructively with the regulatory agencies in these states, as well as with federal regulatory agencies in a way that benefits our customers, shareholders and other stakeholders. We believe the dynamic energy environment in which we operate demands that we maintain an open, respectful and ongoing dialogue with these agencies. This posture is the best way to ensure we are working toward common solutions to the many issues our industry faces. These issues include the changing nature of resource availability, pricing volatility, price levels and their effect on economic development in our service territories, the likelihood of increased importation of LNG and the need for reasonably priced alternatives for our customers to meet their rapidly growing peak demands. For more information regarding pending federal and state regulatory matters, see "Results of Operations – Distribution Operations" and "Results of Operations – Wholesale Services."

TECHNOLOGY INITIATIVES

We continue to make progress with regard to several of our strategic technology initiatives. During the third quarter of 2004, we implemented new technological tools that enable marketers of natural gas in Georgia (Marketers) to create and input service orders directly into Atlanta Gas Light's systems, eliminating the need for duplicate data entry or three-way calls between the customer, Marketers and our customer call center. This system allowed for a reduction in the number of customer service representatives servicing Marketers in our call center, while providing enhanced service to Marketers. It also allowed us to further develop our strategy for the replacement of our customer information system, which should result in less capital investment over time than previously estimated.

In addition, we implemented our new energy trading and risk management (ETRM) system at Sequent in the fourth quarter of 2004. The ETRM system is designed to enhance internal controls and provide additional transparency into the activities of Sequent's business. We also anticipate the system will enable Sequent to continue to grow its commercial business without significant growth in support staff.

INTERNAL CONTROLS

Section 404 of the Sarbanes-Oxley Act of 2002 (SOX 404) Compliance

SOX 404 and related rules of the SEC require management of public companies to assess the effectiveness of the company's internal controls over financial reporting as of the end of each fiscal year. This includes disclosure of any material weaknesses in the company's internal controls over financial reporting that have been identified by management. In addition, SOX 404 requires the company's independent auditor to attest to and report on management's annual assessment of the company's internal controls over financial reporting. We have documented, tested and assessed our systems of internal control over financial reporting, as required under SOX 404 and Public Accounting Oversight Board Standard No. 2, "An Audit of Internal Control Over Financial Reporting Performed in Conjunction With An Audit of Financial Statements" (Standard No. 2), which was adopted in June 2004, to provide the basis for management's report and our independent auditors' attestation on the effectiveness of our internal control over financial reporting as of December 31, 2004. We estimate our Sox 404 compliance costs in 2004 were approximately $8 million, which include $5 million of external costs.

There are three levels of possible deficiencies in our internal controls over financial reporting that can be identified during our assessment phase, which are

- an internal control deficiency, which exists when the design or the operation of a control does not allow management or employees, in the normal course of performing their functions, to prevent or detect misstatements on a timely basis
- a significant deficiency, which exists when an internal control deficiency or a combination of internal controls deficiencies adversely affects our ability to initiate, authorize, record, process or report financial data in accordance with accounting principles generally accepted in the United States of America (GAAP) such that there is a more-than-remote likelihood that a misstatement of the annual or interim financial statements that is more than inconsequential will not be prevented or detected
- a material weakness, which exists when a significant deficiency or a combination of significant deficiencies results in a more-than-remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected

As a result, our assessment could result in two possible outcomes at our reporting date:

- We could conclude that our internal controls over financial reporting were designed and were operating effectively, or
- We could conclude that our internal controls over financial reporting were not properly designed or did not operate effectively. A material weakness that exists at the reporting date would require our assessment to be that our internal controls over financial reporting are not effective, and we would be required to disclose such material weaknesses.

Our independent auditor is now required to issue three opinions annually, beginning with our 2004 consolidated financial statements. First, the auditor must evaluate and opine regarding the process by which we assessed the effectiveness of our internal controls over financial reporting. A second opinion must be issued as to the effectiveness of our internal controls over financial reporting. Finally, the independent auditor must issue an opinion, as is normally done, as to whether our consolidated financial statements are fairly presented, in all material respects.

The scope of our assessment of our internal controls over financial reporting included all of our consolidated entities except those falling under NUI, which we acquired on November 30, 2004, and Jefferson Island, which we acquired on October 1, 2004. In accordance with the SEC's published guidance, we excluded these entities from our assessment as they were acquired late in the year, and it was not possible to conduct our assessment between the date of acquisition and the end of the year. SEC rules require that we complete our assessment of the internal control over financial reporting of these entities within one year from the date of acquisition.

We have completed the assessment of the effectiveness of our internal controls over financial reporting as of December 31, 2004, and have concluded that our controls are operating effectively. Our report on internal control over financial reporting and our independent auditors' reports are included following the notes to the financial statements.

NUI Internal Control Weaknesses

NUI's external and internal auditors performed audits during NUI's fiscal 2003 and 2004 years that identified material weaknesses in NUI's internal controls. These weaknesses were previously discussed in NUI's filings with the SEC. In March 2004, additional internal control issues and deficiencies were identified in the focused audit of NUI that was conducted at the request of the New Jersey Board of Public Utilities (NJBPU). These deficiencies resulted in a material weakness in internal controls over NUI's financial reporting process and also resulted in a need for NUI to restate certain of its financial statements. The internal control deficiencies reported by NUI that were identified by NUI's external and internal auditors included, but were not limited to, the following:

- General ledger cash account balances were not being reconciled to the bank statements.
- General ledger account analyses were not being consistently performed.
- A listing of debt covenants was not being maintained.
- Comprehensive and formalized accounting and financial reporting policies and procedures did not exist.
- Instances were noted where management lacked certain technical accounting and tax expertise that resulted in accounting errors.
- The flow of accounting information between business units and corporate accounting was not timely or formalized.
- Accounts payable invoice processing procedures needed to be improved.
- A formal plan and implementation timetable needed to be developed to address compliance with the certification requirements of SOX 404.
- The contract review process was not formally documented, and appropriate procedures had not been developed to ensure timely review of contracts for accounting implications.
- There was a lack of adherence to policies and procedures for travel and entertainment expense reimbursements and procurement card expenditures.
- The payroll timekeeping and tracking process was manual in nature and prone to errors.
- Information technology had a number of areas where formal, documented policies and procedures had not been developed.

The focused audit conducted at the request of the NJBPU revealed the following accounting concerns and weaknesses:

- inappropriate and inaccurate treatment of intercompany payable and receivable balances
- inappropriate use of a common cash pool
- lack of a formal cash management agreement
- weaknesses in internal controls for accounts payable and receivable
- lack of formal or appropriate policies and procedures in certain accounting functions
- the need to audit procedures for fixed asset and continuing property records functions

To address the deficiencies in its internal controls and procedures noted above, NUI expanded its internal controls and procedures to include the additional analysis and other postclosing procedures described below. The company

- provided comprehensive in-house training in early fiscal 2004 covering the financial reporting process and internal accounting controls, including NUI's written accounting policies and procedures and a policy on disclosure controls, to individuals who participate in the preparation of the company's financial statements and required disclosures
- conducted meetings in which NUI's President and CEO, Vice President and CFO, General Counsel and Secretary reviewed and discussed accounting and operational issues to ensure completeness and accuracy of disclosures in NUI's SEC filings
- requested that NUI's in-house counsel and key financial and operational personnel provide information regarding any known commitments and contingencies that may have financial statement and/or disclosure implications
- obtained internal certifications from key accounting and operational personnel indicating that they reviewed drafts of NUI's SEC filings for completeness and accuracy
- conducted formal meetings, led by NUI's Corporate Controller with participation of key accounting personnel (prior to closing the books of account and filing required reports), to identify and resolve accounting and disclosure issues
- prepared and distributed to participants involved in the preparation and review of NUI's SEC filings a detailed time schedule outlining key dates and responsibilities for the preparation of financial information and required disclosures
- completed an audit disclosure checklist to ensure all disclosures required by GAAP and applicable securities laws and regulations were properly addressed

- assembled supporting documentation for disclosures made in its SEC filings
- retained external counsel to review drafts of its SEC filings to assist management in ensuring compliance with SEC rules and regulations
- created documentation, including flowcharts and formal written policies and procedures of NUI's financial reporting process, to assist management with its responsibility to ensure key internal accounting controls are identified and addressed
- distributed a business ethics policy to all employees requesting their acknowledgment that they received, read and complied with the ethics policy
- conducted internal audits to evaluate internal accounting controls of key business functions

We have initiated our efforts to assess the systems of internal control related to NUI's business to comply with the requirements of both Sections 302 and 404 of the Sarbanes-Oxley Act of 2002. We believe that material deficiencies in internal controls discussed above related to the NUI business persist and that we are required to address and resolve these deficiencies. Our integration plans with respect to the NUI businesses include the integration and conversion of NUI's accounting systems and internal control processes into our accounting systems and internal control processes, the majority of which we expect to complete during the first quarter of 2005. In addition, we have incorporated the NUI businesses into our disclosure control processes, which include the same or similar activities to those undertaken by NUI management described above, as well as other procedures, in our closing and financial reporting process.

RESULTS OF OPERATIONS

AGL RESOURCES

We acquired Jefferson Island on October 1, 2004 and NUI on November 30, 2004. As a result, our results of operations for 2004 include three months of the acquired operations of Jefferson Island and one month of the acquired operations of NUI. Pursuant to Financial Accounting Standards Board (FASB) Interpretation No. 46, "Consolidation of Variable Interest Entities," as revised (FIN 46R), which we adopted in January 2004, we consolidated all of SouthStar's accounts with our subsidiaries' accounts as of January 1, 2004. We recorded Piedmont Natural Gas Company, Inc.'s (Piedmont) portion of SouthStar's earnings as a minority interest in our statements of consolidated income and Piedmont's portion of SouthStar's contributed capital as a minority interest on our consolidated balance sheet. We eliminated any intercompany profits between segments.

Revenues

We generate nearly all our operating revenues through the sale, distribution and storage of natural gas. We include in our consolidated revenues an estimate of revenues from natural gas distributed, but not yet billed, to residential and commercial customers from the latest meter reading date to the end of the reporting period. We record these estimated revenues as unbilled revenues on our consolidated balance sheet.

A significant portion of our operations is subject to variability associated with changes in commodity prices and seasonal fluctuations. During the heating season, which is primarily from November through March, natural gas usage and operating revenues are higher since generally more customers will be connected to our distribution systems and natural gas usage is higher in periods of colder weather than in periods of warmer weather. Additionally, commodity prices tend to be higher in colder months. Our nonutility businesses principally use physical and financial arrangements to economically hedge the risks associated with seasonal fluctuations and changing commodity prices. Certain hedging and trading activities may require cash deposits to satisfy margin requirements. In addition, because these economic hedges do not generally qualify for hedge accounting treatment, our reported earnings for the wholesale services and energy investments segments reflect changes in the fair value of certain derivatives; these values may change significantly from period to period.

Operating Margin and EBIT

We evaluate the performance of our operating segments using the measures of operating margin and EBIT. We believe operating margin is a better indicator than revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of gas can vary significantly and is generally passed directly to our customers. We also consider operating margin to be a better indicator in our wholesale services and energy investments segments since it is a direct measure of gross profit before overhead costs. We believe EBIT is a useful measurement of our operating segments' performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations.

Our operating margin and EBIT are not measures that are considered to be calculated in accordance with GAAP. You should not consider operating margin or EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our operating margin or EBIT measures may not be comparable to a similarly titled measure of another company. The following are reconciliations of our operating margin and EBIT to operating income and net income, and other consolidated financial information for the years ended December 31, 2004, 2003 and 2002.

In millions, except per share amounts	2004	2003	2002
Operating revenues	$1,832	$ 983	$ 877
Cost of gas	994	339	268
Operating margin	838	644	609
Operating expenses			
Operation and maintenance	377	283	274
Depreciation and amortization	99	91	89
Taxes other than income taxes	30	28	29
Total operating expenses	506	402	392
Gain on sale of Caroline Street campus	—	16	—
Operating income	332	258	217
Other income	—	40	30
Minority interest	(18)	—	—
EBIT	314	298	247
Interest expense	71	75	86
Earnings before income taxes	243	223	161
Income taxes	90	87	58
Income before cumulative effect of change in accounting principle	153	136	103
Cumulative effect of change in accounting principle	—	(8)	—
Net income	$ 153	$ 128	$ 103
Basic earnings per common share			
Income before cumulative effect of change in accounting principle	$ 2.30	$ 2.15	$1.84
Cumulative effect of change in accounting principle	—	(0.12)	—
Basic earnings per common share	$ 2.30	$ 2.03	$1.84
Fully diluted earnings per common share			
Income before cumulative effect of change in accounting principle	$ 2.28	$ 2.13	$1.82
Cumulative effect of change in accounting principle	—	(0.12)	—
Fully diluted earnings per common share	$ 2.28	$ 2.01	$1.82
Weighted average number of common shares outstanding			
Basic	66.3	63.1	56.1
Fully diluted	67.0	63.7	56.6

2004 Compared to 2003

Our earnings per share and net income for 2004 were higher than the prior year due to stronger contributions from our wholesale services business, SouthStar and the acquisitions of NUI and Jefferson Island. The following table provides a summary of certain items that impacted 2004 earnings.

In millions	Increase (Decrease) in 2004 Operating Income (Before Taxes)
Accelerated recognition of margins associated with Sequent storage positions originally were anticipated to be liquidated in the first quarter of 2005	$ 5
Asset sales in the second quarter of 2004 for a residential and retail property in Savannah, Georgia which resulted in a $2 million contribution to EBIT and the sale of our remaining investment units in U.S. Propane LP (US Propane)	3
Change in Atlanta Gas Light's property taxes as a result of revised estimates and intangible property tax assessment	3
Contributions to the AGL Resources Private Foundation Inc. and for energy assistance by our subsidiary SouthStar	(3)

The distribution operations segment's EBIT for 2004 was $247 million, equal to 2003 results. For comparison purposes, however, the distribution operations segment's EBIT in 2004 increased by $13 million, after excluding the effect of a net $13 million pretax gain on the sale of company property and a related charitable contribution in 2003. In addition, 2004 EBIT includes a $7 million contribution from NUI.

Operating margins of the distribution operations segment improved by $42 million or 7%, primarily as a result of the acquisition of NUI ($25 million) and an approximately 2% increase in the total number of average connected customers at Atlanta Gas Light, Chattanooga Gas and Virginia Natural Gas. Operating expenses increased $29 million or 8% in 2004 relative to 2003, primarily as a result of NUI ($19 million) and increased costs related to information technology projects, regulatory activities (including Sarbanes-Oxley compliance) and depreciation expense, offset by decreased bad debt expense and a decrease in costs associated with postretirement benefits.

The wholesale services segment contributed $24 million in EBIT in 2004 compared with $20 million in 2003. The $4 million increase is primarily the result of unusually strong fourth-quarter 2004 results, reflecting the accelerated recognition of margins associated with storage positions that originally were anticipated to be liquidated in the first quarter of 2005. The accelerated margin recognition resulted in $5 million of operating income in the fourth quarter that otherwise would have been recognized in the first quarter of 2005. Primarily as a result of the decline in forward gas prices at the end of December 2004, and the positive mark-to-market impact that decline had on the futures contracts Sequent utilizes to economically hedge its storage positions, approximately $18 million or 75% of Sequent's full-year EBIT contribution was generated in the fourth quarter of 2004.

Sequent also continued to increase its volumes and business transaction activity in 2004. Full-year volumes increased 20%, from 1.75 billion cubic feet (Bcf) per day in 2003 to 2.10 Bcf per day in 2004. New peaking and third-party asset management transactions also contributed to strong results for the year. Sequent's operating expenses for 2004 were $29 million compared with $20 million in 2003. The increase was due primarily to increased personnel and increased costs associated with the implementation of a new energy trading and risk management system and Sarbanes-Oxley 404 compliance.

The energy investments segment contributed EBIT of $59 million in 2004, a 37% increase over the segment's $43 million contribution in 2003. The primary driver of this segment's results was the performance of SouthStar, which contributed $53 million in EBIT in 2004 compared with $46 million in 2003. The improved results at SouthStar mainly reflected higher commodity margins and decreased bad debt expense during the year. Energy investments' EBIT contribution increased due to higher contributions from AGL Networks LLC (AGL Networks) and the acquisition of Jefferson Island in October 2004.

The corporate segment EBIT contribution decreased by $4 million to $(16) million in 2004, primarily the result of costs associated with information technology projects, SOX 404 compliance and merger- and acquisition-related expenses.

Interest expense for 2004 was $71 million, which was $4 million lower than in 2003. A favorable interest rate environment and the issuance of lower-interest long-term debt combined to lower the company's interest expense in 2004 relative to the previous year. The increase of $19 million in average debt outstanding for 2004 compared to 2003 was due to additional debt incurred as a result of the acquisitions of NUI and Jefferson Island.

Dollars in millions	2004	2003	2004 vs. 2003
Total interest expense	$ 71	$ 75	$ (4)
Average debt outstanding[1]	1,274	1,255	19
Average rate	5.6%	6.0%	(0.4)%

[1] Daily average of all outstanding debt.

Based on variable-rate debt outstanding at December 31, 2004, a 100 basis point change in market interest rates from 3.1% to 4.1% would result in a change in annual pretax interest expense of $5 million. We anticipate that our interest expense in 2005 will be higher than in 2004 due to the following:

- higher projected short-term interest rates based on higher 2005 London Interbank Offered Rate (LIBOR) rates
- higher debt balances and higher interest rates from 2004 and 2005 on debt issued for the acquisitions of NUI and Jefferson Island

The increase in income tax expense of $3 million or 3% for 2004 compared to 2003 reflected $8 million of additional income taxes due to higher corporate earnings year-over-year, offset by a $5 million decrease in income taxes due to a decrease in the effective tax rate from 39% in 2003 to 37% in 2004. The decline in the effective tax rate was primarily the result of income tax adjustments recorded in the third quarter of 2004 in connection with our annual comparison of our filed tax returns to the related income tax accruals. We expect our effective tax rate for the year ending December 31, 2005 to be higher due to the favorable adjustments recorded in 2004 and the higher state income tax rate that will be applicable to earnings from Elizabethtown Gas Company (Elizabethtown Gas) in New Jersey.

As a result of the company's 11 million share equity offering in November 2004, earnings results for the year are based on weighted average shares outstanding of 66.3 million, while 2003 results were based on weighted average shares outstanding of 63.1 million. Currently, we have approximately 76.9 million shares outstanding.

2003 Compared to 2002

Net income increased $25 million or 24% from 2002, reflecting higher earnings at each operating segment. EBIT from distribution operations, excluding the net gain on the sale of the Caroline Street campus of $13 million, increased 4% to $234 million from $225 million in 2002 due to higher operating margins, an increase in the number of connected customers and increased pipeline replacement revenue in 2003. Wholesale services contributed $20 million in EBIT compared to $9 million in 2002. The earnings improvement resulted primarily from Sequent's optimization of various transportation and storage assets and increased physical volumes sold as well as increased margins driven by favorable pricing and market volatility, particularly in the first quarter of 2003.

Energy investments contributed $43 million in EBIT compared to $24 million in 2002. SouthStar accounted for the majority of the increase, and its results were driven primarily by higher operating margins, reduced bad debt expense, our expanded ownership interest in the business and the resolution of an income-sharing issue with Piedmont. Our corporate segment's expenses decreased primarily as a result of favorable interest expense and lower average debt balances. The 7 million share increase in our weighted average shares outstanding was a result of our 6.4 million share equity offering in February 2003.

The following table shows the impact of the 2003 sale of our Caroline Street campus and the related donation to the private foundation:

In millions	Distribution Operations	Corporate	Consolidated
Gain (loss) on sale of Caroline Street campus	$21	$ (5)	$16
Donation to private foundation	(8)	—	(8)
EBIT	13	(5)	8
Income taxes			(3)
Net income			$ 5

The decrease in interest expense of $11 million or 13% for 2003 compared to 2002 was a result of lower average debt balances, as shown in the following table, due primarily to the proceeds generated from our public offering of 6.4 million shares of common stock in February 2003; repayment of Medium-Term notes, which had higher rates than our bond issuance in July 2003; the benefits of our interest rate swaps; and lower interest rates on commercial paper borrowings.

Dollars in millions	2003	2002	2003 vs. 2002
Total interest expense	$ 75	$ 86	$ (11)
Average debt outstanding[1]	1,255	1,412	(157)
Average rate	6.0%	6.1%	(0.1)%

[1] Daily average of all outstanding debt.

The increase in income tax expense of $29 million or 50% for 2003 compared to 2002 was primarily due to the increase in earnings before income taxes of $62 million or 39% and an increase in our effective tax rate from 36% in 2002 to 39% in 2003. The increase in the effective tax rate for 2003 was primarily due to higher projected state income taxes resulting from a change in Georgia law governing the methodology by which Georgia companies must compute their tax liabilities and to the accrual of deferred tax liabilities related to temporary differences between the book and tax basis of some of our assets.

Consolidation of SouthStar

Below are our unaudited pro-forma condensed consolidated balance sheet and statement of income, presented as if SouthStar's balances were consolidated with our subsidiaries' accounts as of December 31, 2003. This pro-forma presentation is a non-GAAP presentation; however, we believe this pro-forma presentation is useful to the readers of our financial statements since it presents our financial statements for prior years on the same basis as 2004 following our consolidation of SouthStar pursuant to our adoption of FIN 46R. These unaudited pro-forma amounts are presented only for comparative purposes. The eliminations include intercompany eliminations, our investment in SouthStar, SouthStar's capitalization and our equity in earnings from SouthStar.

Pro-forma condensed consolidated balance sheet December 31, 2003

In millions	As Reported	SouthStar	Eliminations	(Unaudited) Pro-forma
Current assets	$ 742	$174	$ (11)	$ 905
Property, plant and equipment	2,352	2	—	2,354
Deferred debits and other assets[1]	878	—	(71)	807
Total assets	$3,972	$176	$ (82)	$4,066
Current liabilities	$1,048	$ 75	$ (11)	$1,112
Accumulated deferred income taxes	376	—	—	376
Long-term liabilities	569	—	—	569
Deferred credits	78	—	—	78
Minority interest[2]	—	—	30	30
Capitalization	1,901	101	(101)	1,901
Total liabilities and capitalization	$3,972	$176	$ (82)	$4,066

[1] Our investment in SouthStar was $71 million.

[2] Minority interest adjusts our balance sheet to reflect Piedmont's portion of SouthStar's contributed capital.

Pro-forma condensed consolidated statement of income for the year ended December 31, 2003

In millions	As Reported	SouthStar[1]	Eliminations	(Unaudited) Pro-forma
Operating revenues	$983	$746	$(169)	$1,560
Operating expenses				
Cost of gas	339	622	(169)	792
Operation and maintenance expenses	283	60	—	343
Depreciation and amortization	91	1	—	92
Taxes other than income	28	—	—	28
Total operating expenses	741	683	(169)	1,255
Gain on sale of Caroline Street campus	16	—	—	16
Operating income	258	63	—	321
Equity earnings from SouthStar	46	—	(46)	—
Donation to private foundation	(8)	—	—	(8)
Other income	2	—	—	2
Interest expense	(75)	—	—	(75)
Minority interest in income of consolidated subsidiary[2]	—	—	(17)	(17)
Earnings before income taxes	223	63	(63)	223
Income taxes	(87)	—	—	(87)
Income before cumulative effect of change in accounting principle	$136	$ 63	$ (63)	$ 136

[1] Includes 100% of SouthStar's revenues and expenses for comparisons of SouthStar's consolidation in 2004.

[2] Minority interest adjusts our earnings to reflect our 80% share of SouthStar's earnings, less Dynegy Inc.'s 20% share of SouthStar's income prior to February 18, 2003.

Pro-forma condensed consolidated statement of income for the year ended December 31, 2002

In millions	As Reported	SouthStar[1]	Eliminations	(Unaudited) Pro-forma
Operating revenues	$877	$630	$(171)	$1,336
Operating expenses				
Cost of gas	268	515	(171)	612
Operation and maintenance expenses	274	72	—	346
Depreciation and amortization	89	2	—	91
Taxes other than income	29	—	—	29
Total operating expenses	660	589	(171)	1,078
Operating income	217	41	—	258
Equity earnings from SouthStar	27	—	(27)	—
Other income	3	1	—	4
Interest expense	(86)	—	—	(86)
Minority interest in income of consolidated subsidiary[2]	—	—	(15)	(15)
Earnings before income taxes	161	42	(42)	161
Income taxes	(58)	—	—	(58)
Net income	$103	$ 42	$ (42)	$ 103

[1] Includes 100% of SouthStar's revenues and expenses for comparisons of SouthStar's consolidation in 2004.

[2] Minority interest adjusts our earnings to reflect our 50% share of SouthStar's earnings.

Segment Information

Operating revenues, operating margin and EBIT information for each of our segments are contained in the following table for the years ended December 31, 2004, 2003 and 2002:

In millions	Operating Revenues	Operating Margin	EBIT
2004			
Distribution operations	**$1,111**	**$641**	**$247**
Wholesale services	**54**	**53**	**24**
Energy investments	**852**	**145**	**59**
Corporate[1]	**(185)**	**(1)**	**(16)**
Consolidated	**$1,832**	**$838**	**$314**
2003			
Distribution operations	$ 936	$599	$247
Wholesale services	41	40	20
Energy investments	6	5	43
Corporate	—	—	(12)
Consolidated	$ 983	$644	$298
2002			
Distribution operations	$ 852	$585	$225
Wholesale services	23	23	9
Energy investments	2	1	24
Corporate	—	—	(11)
Consolidated	$ 877	$609	$247

[1] Includes the elimination of intercompany revenues.

DISTRIBUTION OPERATIONS

Distribution operations includes our natural gas local distribution utility companies, which construct, manage and maintain natural gas pipelines and distribution facilities and serve more than 2.2 million end-use customers. Distribution operations' revenues contributed 61% of our consolidated revenues for 2004, 95% for 2003 and 97% for 2002. The decrease of 34% in the contribution of distribution operations' revenues from 2003 is due to the impact of our consolidation of SouthStar in 2004. The following table provides operational information for our larger utilities. The daily capacity represents total system capability and the storage capacity includes on-system LNG and propane volumes.

	Atlanta Gas Light	Elizabethtown Gas	Virginia Natural Gas	Florida Gas	Chattanooga Gas
Average end-use customers (in thousands)[1]	1,533	266	256	104	60
Daily capacity[2]	2.5	0.4	0.4	0.1	0.2
Storage capacity[2]	55.6	14.0	10.2	—	4.8
2004 peak-day demand[2]	1.8	0.4	0.3	0.04	0.1
Average monthly throughput[2]	19.8	5.0	2.9	0.8	1.4
Authorized return on rate base[3,4]	9.16%	7.95%	9.24%	7.36%	7.43%
Authorized return on equity[4]	10.0–12.0%	10.0%	10.0–11.4%	11.25%	10.2%
Authorized rate base % of equity[4]	47.0%	53.0%	52.4%	36.8%	35.5%
Estimated 2004 return on equity[4,5]	11.2%	5.2%	11.4%	6.6%	9.4%
Rate base included in estimated 2004 return of equity (in millions)[6,7]	$1,120	$397	$325	$125	$94

[1] Represents an average for 2004 except Elizabethtown Gas and Florida City Gas Company (Florida Gas) which are December 2004 amounts.

[2] In millions of dekatherms.

[3] The authorized return on rate base for Florida Gas includes a credit for deferred taxes that is considered a rate base deduction in all other jurisdictions.

[4] The authorized returns on rate base and equity along with authorized rate base % of equity for Chattanooga Gas are currently under reconsideration by the Tennessee Regulatory Authority (Tennessee Authority). The estimated 2004 return on equity for Chattanooga Gas is calculated consistent with the Tennessee Authority order that is under reconsideration.

[5] Estimate based on principles consistent with utility ratemaking in each jurisdiction. Returns are not consistent with GAAP returns.

[6] Based on 13 month average.

[7] Elizabethtown Gas is based on amounts filed in a 2002 rate case; however no specific level of rate base was authorized due to settlement by stipulation with NJBPU.

Each utility operates subject to regulations provided by the state regulatory agencies in its service territories with respect to rates charged to our customers, maintenance of accounting records and various other service and safety matters. Rates charged to our customers vary according to customer class (residential, commercial or industrial) and rate jurisdiction. Rates are set at levels that allow for the recovery of all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return on common equity. Rate base consists generally of the original cost of utility plant in service, working capital, inventories and certain other assets; less accumulated depreciation on utility plant in service, net deferred income tax liabilities and certain other deductions. We continuously monitor the performance of our utilities to determine whether rates need to be adjusted by making a rate case filing.

Competition

Our distribution operations businesses face competition based on our customers' preferences for natural gas compared to other energy products and the comparative prices of those products. Our principal competition relates to the electric utilities and oil and propane providers serving the residential and small commercial markets throughout our service areas and the potential displacement or replacement of natural gas appliances with electric appliances. The primary competitive factors are the price of energy and the desirability of natural gas heating versus alternative heating sources. Also, price volatility in the wholesale natural gas commodity market has resulted in increases in the cost of natural gas billed to customers.

Competition for space heating and general household and small commercial energy needs generally occurs at the initial installation phase when the customer/builder typically makes decisions as to which types of equipment to install and operate. The customer will generally continue to use the chosen energy source for the life of the equipment. Our customers' demand for natural gas and the level of business of natural gas assets could be affected by numerous factors, including

- changes in the availability or price of natural gas and other forms of energy
- general economic conditions
- energy conservation
- legislation and regulations
- the capability to convert from natural gas to alternative fuels
- weather

In 2004, our distribution operations segment's customers grew by approximately 2%. However, in some of our service areas, primarily in Georgia, overall growth continues to be limited due to the number of customers who choose to leave our systems. We expect our customer growth to improve in the future through our efforts in new business and retention. These efforts include working to add residential customers with three or more appliances, multifamily complexes and high-value commercial customers that use natural gas for purposes other than space heating. In addition, we partner with numerous entities to market the benefits of gas appliances and to identify potential retention options early in the process for those customers who might consider leaving our franchise by converting to alternative fuels.

Our distribution operations utilities include:

Atlanta Gas Light is a natural gas local distribution utility with distribution systems and related facilities throughout Georgia. Atlanta Gas Light has approximately 6 Bcf of LNG storage capacity in three LNG plants to supplement the supply of natural gas during peak usage periods. Atlanta Gas Light is regulated by the Georgia Public Service Commission (Georgia Commission).

Prior to Georgia's 1997 Natural Gas Competition and Deregulation Act (Deregulation Act), which deregulated Georgia's natural gas market, Atlanta Gas Light was the supplier and seller of natural gas to its customers. Today Marketers — that is, marketers who are certificated by the Georgia Commission to sell retail natural gas in Georgia at rates and on terms approved by the Georgia Commission — sell natural gas to the end-use customers in Georgia and are handling customer billing functions. Atlanta Gas Light's role includes

- distributing natural gas for Marketers
- constructing, operating and maintaining the gas system infrastructure, including responding to customer service calls and leaks
- performing meter reading and maintaining underlying customer premise information for Marketers

Since 1998, a number of federal and state proceedings have addressed the role of Atlanta Gas Light in administering and assigning interstate assets to Marketers pursuant to the provisions of the Deregulation Act. In this role, Atlanta Gas Light is authorized to offer additional sales services pursuant to Georgia Commission–approved tariffs and to acquire and continue managing the interstate transportation and storage contracts that underlie the sales services provided to Marketers on its distribution system under Georgia Commission–approved tariffs.

Performance-based Rates Atlanta Gas Light's revenues are established pursuant to a three-year performance-based rate (PBR) plan that became effective May 1, 2002, with an authorized return on equity of 11%. The PBR plan also establishes an earnings band based on a return on equity of 10% to 12%, subject to certain adjustments, with three-quarters of any earnings above a 12% return on equity shared with Georgia customers and one-quarter retained by Atlanta Gas Light.

The Georgia Commission staff has reviewed the operation of the plan and Atlanta Gas Light's revenue requirement to determine whether base rates should be reset upon the expiration of the existing plan in April 2005. The Georgia Commission will then determine whether the plan should be discontinued, extended or otherwise modified.

In connection with this review, Atlanta Gas Light filed a general rate case request for a $26 million rate increase with the Georgia Commission. The request would continue the PBR plan and include a return on equity band of 10.2% to 12.2%. The Georgia Commission is scheduled to issue its decision on April 28, 2005, with any rate adjustments to be effective May 1, 2005. Any rate adjustments would be comprised of changes from May 1, 2002 and projected through April 30, 2005 related to depreciation expense, capital expenditures and various other operating expenses such as pipeline integrity costs mandated by federal regulations and changes in the property tax valuation method.

Pipeline Replacement Program (PRP) Pursuant to the Georgia Commission's revised procedural and scheduling order, Atlanta Gas Light's rate case filing included testimony on whether the PRP should be included in Atlanta Gas Light's base rates or whether the rider currently used for recovery of PRP expenses should be otherwise modified or discontinued. Atlanta Gas Light's testimony supported continuing the current PRP rider agreement. Including the PRP capital costs in base rates before the end of the program would result in a regulatory delay in recovery of our total unrecovered PRP regulatory asset of $361 million. This delay could require more frequent rate requests to fund the annual cost of PRP capital expenditures and resulting depreciation. In addition, the future loss of a recovery mechanism could impair the PRP regulatory asset. Any resulting impairment would reduce Atlanta Gas Light's earnings.

Straight-fixed-variable Rates Atlanta Gas Light's revenue is recognized under a straight-fixed-variable rate design, whereby Atlanta Gas Light charges rates to its customers based primarily on monthly fixed charges. This mechanism minimizes the seasonality of revenues since the fixed charge is not volumetric and the monthly charges are not set to be directly weather dependent. Weather indirectly influences the number of customers that have active accounts during the heating season, and this has a seasonal impact on Atlanta Gas Light's revenues since generally more customers will be connected in periods of colder weather than in periods of warmer weather.

Interstate Pipeline Acquisition Atlanta Gas Light has executed an agreement with Southern Natural, a subsidiary of El Paso Corporation, to acquire a portion of Southern Natural's interstate pipeline that runs from Macon, Georgia to the vicinity of Atlanta, Georgia. The transaction is valued at approximately $32 million. As part of the agreement, Atlanta Gas Light will extend certain existing Southern Natural transportation and storage contracts to ensure reliable delivery of natural gas into Georgia in return for the right to expand Atlanta Gas Light's system off of the purchased facilities. On January 19, 2005, the Federal Energy Regulatory Commission (FERC) approved the abandonment of Southern Natural's facilities to Atlanta Gas Light, thereby allowing the transaction to proceed to closing. We expect the Southern Natural transaction to close by April 30, 2005, subject to securing the remaining regulatory approvals.

Capacity Supply Plan In May 2004, Atlanta Gas Light and 8 of the 10 Marketers entered into a settlement that resolved matters related to a capacity supply plan that was required to be filed by Atlanta Gas Light in July 2004. As a result of the settlement, the parties filed a three-year capacity supply plan for the Georgia market with the Georgia Commission. In October 2004, we received reconsideration and approval by the Georgia Commission of the capacity supply plan, which includes, among other things:

- calculation of the design (peak) day requirements for the next three years
- purchase by Atlanta Gas Light of the above-described Southern Natural facilities and the recovery of those costs through the pending rate case
- construction of a pipeline from the Macon LNG facility to the purchased Southern Natural facilities
- extension of the Sequent peaking contract to March 2005
- approval of Sequent's current asset management contract for retained assets through March 1, 2006
- other tariff provisions

Elizabethtown Gas is a natural gas local distribution utility that we acquired with our NUI acquisition with distribution systems and related facilities in central and northwestern New Jersey. Elizabethtown Gas has an LNG storage and vaporization facility to supplement the supply of natural gas during peak usage periods. The facility has a daily capacity of 24,200 million cubic feet (Mcf) and storage capacity of 131,000 Mcf. Most of Elizabethtown Gas' customers are located in densely populated central New Jersey, where increases in the number of customers primarily result from conversions to gas heating from alternative forms of heating. In the northwest region of the state, customer additions are driven primarily by new construction. Elizabethtown Gas is regulated by the NJBPU.

On November 9, 2004, the NJBPU approved our acquisition of NUI and our agreement with the NJBPU's staff and certain third parties related to postclosing operations. This agreement provided, among other things, for

- a freeze of Elizabethtown Gas' base rates for five years, with earnings over an 11% return of equity to be shared with ratepayers in the fourth and fifth years
- Sequent to serve as asset manager for Elizabethtown Gas, beginning April 1, 2005, for a three-year term for an annual fixed-fee payment by Sequent to Elizabethtown Gas of $4 million
- new performance standards with respect to customer satisfaction, safety and reliability, with negotiations with the various interested parties of the applicable standards beginning in February 2005
- acceleration of the payment of the outstanding balances due on Elizabethtown Gas' $28 million refund to its ratepayers and a related $2 million penalty to the NJBPU
- a commitment to make $9 million available for the purpose of enhancing severance packages for certain employees located in New Jersey

Weather Normalization Elizabethtown Gas' tariff contains a weather normalization clause that is designed to help stabilize Elizabethtown Gas' results by increasing base rate amounts charged to customers when weather has been warmer than normal and decreasing amounts charged when weather is colder than normal. The weather normalization clause was renewed in October 2004 and is based on the 20-year average of weather conditions.

Virginia Natural Gas is a natural gas local distribution utility with distribution systems and related facilities in southeastern Virginia. Virginia Natural Gas owns and operates approximately 155 miles of a separate high-pressure pipeline that provides delivery of gas to customers under firm transportation agreements within the state of Virginia. Virginia Natural Gas also has approximately 5 million gallons of propane storage capacity in its two propane facilities to supplement the supply of natural gas during peak usage periods. Virginia Natural Gas is regulated by the Virginia State Corporation Commission (Virginia Commission).

Weather Normalization Adjustment (WNA) On September 27, 2002, the Virginia Commission approved a WNA program as a two-year experiment involving the use of special rates. The WNA program's purpose is to reduce the effect of weather on customer bills by reducing bills when winter weather is colder than normal and increasing bills when winter weather is warmer than normal. In September 2004, Virginia Natural Gas received approval from the Virginia Commission to extend Virginia Natural Gas' WNA program for an additional two years with certain modifications to the existing program. The significant modifications include the removal of the commercial class of customers from the WNA program and the use of a rolling 30-year average to calculate the weather factor that is updated annually.

Propane-air Facility In June 2004, the Virginia Commission issued its final order authorizing the recovery by Virginia Natural Gas of all charges for the services of a new propane-air facility through Virginia Natural Gas' gas cost recovery mechanism. The approval is for an initial 10-year term, with the possibility of renewal thereafter for terms of 2 years subject to Virginia Commission approval. The facility will provide Virginia Natural Gas with 28,800 dekatherms (Dth) of propane air per day on a 10-day-per-year basis to more reliably serve its peaking needs.

Florida City Gas Company (Florida Gas) is a natural gas local distribution utility, acquired with our NUI acquisition. Florida Gas has distribution systems and related facilities in central and southern Florida. Florida Gas customers purchase gas primarily for heating water, drying clothes and cooking. Some customers, mainly in central Florida, also purchase gas to provide space heating during the winter season. Florida Gas is regulated by the Florida Public Service Commission (Florida Commission).

In January 2004, Florida Gas received approval from the Florida Commission to increase its base rates by approximately $7 million, effective February 23, 2004. The increase represents a portion of Florida Gas' request for a rate increase to cover the costs of investments in its customer service assets, system maintenance and growth, and increases in its operating expenses.

Chattanooga Gas is a natural gas local distribution utility with distribution systems and related facilities in the Chattanooga and Cleveland areas of Tennessee. Chattanooga Gas has approximately 1.2 Bcf of LNG storage capacity in its LNG plant. Included in the base rates charged by Chattanooga Gas is a weather normalization clause that allows for revenue to be recognized based on a factor derived from average temperatures over a 30-year period, which offsets the impact of unusually cold or warm weather on its operating income. Chattanooga Gas is regulated by the Tennessee Regulatory Authority (Tennessee Authority).

Base Rate Increase In January 2004, Chattanooga Gas filed a rate plan request with the Tennessee Authority for a total rate increase of approximately $5 million annually. The rate plan was filed to cover Chattanooga Gas' rising cost of providing natural gas to its customers. In May 2004, the Tennessee Authority suspended the increase until July 28, 2004 and subsequently deferred the decision to August 30, 2004. After its initial filing, Chattanooga Gas reduced its rate plan increase to approximately $4 million, primarily as a result of the February 2004 Tennessee Authority ruling discussed in "Purchased Gas Adjustment" below. Chattanooga Gas received a written order from the Tennessee Authority on October 20, 2004 that authorized new rates based on a 7.43% return on rate base for an increase in revenues of approximately $1 million annually. In November 2004, the Tennessee Authority granted Chattanooga Gas' motion for reconsideration of the rate increase and in December 2004 heard oral arguments on the issues of the appropriate capital structure and the return on equity to be used in setting Chattanooga Gas' rates. The Tennessee Authority has not yet issued its ruling after reconsideration.

Purchased Gas Adjustment In March 2003, Chattanooga Gas filed a joint petition with other Tennessee distribution companies requesting the Tennessee Authority issue a declaratory ruling that the portion of uncollectible accounts directly related to the cost of its natural gas is recoverable through a Purchased Gas Adjustment (PGA) mechanism. The PGA mechanism allows the local distribution companies to automatically adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure the utilities recover 100% of the cost incurred in purchasing gas for their customers. On February 9, 2004, the Tennessee Authority ruled that the gas portion of accounts written off as uncollectible after March 10, 2004 could be recovered through the PGA.

Elkton Gas Company (Elkton Gas) is a natural gas local distribution utility that we acquired with our NUI acquisition. Elkton Gas has distribution systems and related facilities serving approximately 5,900 customers in Cecil County, Maryland. Elkton Gas customers are approximately 93% commercial and industrial and 7% residential. Elkton Gas' current rates were authorized in June 1992 by the Maryland Public Service Commission.

Virginia Gas Distribution Company is a natural gas local distribution utility that we acquired with our NUI acquisition. Virginia Gas Distribution Company services approximately 300 customers in franchised territories in the southwestern Virginia counties of Buchanan and Russell. Approximately 76% of its natural gas sales are to residential customers with its remaining sales to commercial and industrial customers. Virginia Gas Distribution Company is regulated by the Virginia Commission.

Results of Operations for our distribution operations segment for the years ended December 31, 2004, 2003 and 2002 are shown in the following table:

In millions	2004	2003	2002	2004 vs. 2003	2003 vs. 2002
Operating revenues	**$1,111**	$936	$852	$175	$84
Cost of gas	**470**	337	267	133	70
Operating margin	**641**	599	585	42	14
Operation and maintenance expenses	**286**	261	255	25	6
Depreciation and amortization	**85**	81	82	4	(1)
Taxes other than income	**24**	24	25	—	(1)
Total operating expenses	**395**	366	362	29	4
Gain on sale of Caroline Street campus	**—**	21	—	(21)	21
Operating income	**246**	254	223	(8)	31
Donation to private foundation	**—**	(8)	—	8	(8)
Other income	**1**	1	2	—	(1)
Total other (loss) income	**1**	(7)	2	8	(9)
EBIT	**$ 247**	$247	$225	$ —	$22
Metrics					
Average end-use customers (in thousands)[1]	**1,880**	1,838	1,824	2%	1%
Operation and maintenance expenses per customer	**$152**	$142	$140	7	1
EBIT per customer[2]	**$131**	$127	$123	3	3
Throughput (in millions of Dth)[1]					
Firm	**194**	190	182	2%	4%
Interruptible	**105**	109	124	(4)	(12)
Total	**299**	299	306	—%	(2)%
Heating degree days[3]:					
Florida[1]	**239**	—	—	n/a%	n/a%
Georgia	**2,589**	2,654	2,812	(2)	(6)
Maryland[1]	**860**	—	—	n/a	n/a
New Jersey[1]	**873**	—	—	n/a	n/a
Tennessee	**3,010**	3,168	3,052	(5)	4
Virginia	**3,214**	3,264	3,030	(2)	8

[1] Represents information only for December 2004 for the utilities acquired from NUI.

[2] Excludes the gain on the sale of our Caroline Street campus in 2003.

[3] We measure effects of weather on our businesses using "degree days." The measure of degree days for a given day is the difference between average daily actual temperature and baseline temperature of 65 degrees Fahrenheit. Heating degree days result when the average daily actual temperature is less than the 65 degree baseline. Generally, increased heating degree days result in greater demand for gas on our distribution systems.

2004 Compared to 2003

There was no change in the distribution operations segment's EBIT from 2003; however, the 2003 results included a gain of $21 million on the sale of our Caroline Street campus, offset by an $8 million donation to AGL Resources Private Foundation, Inc. Exclusive of the gain and donation, EBIT increased $13 million or 5% due to increased operating margin that was partially offset by increased operating expenses.

The increase in operating margin of $42 million or 7% from 2003 includes $17 million in combined increases at Atlanta Gas Light and Virginia Natural Gas. The increase in Atlanta Gas Light's operating margin was primarily from higher PRP revenue as a result of continued PRP capital spending, customer growth, higher customer usage and additional carrying charges from gas stored for Marketers due to a higher average cost of gas. The increase in Virginia Natural Gas' operating margin was primarily from customer growth. The acquisition of NUI added $25 million of operating margin primarily from NUI's December operations of Elizabethtown Gas and Florida Gas.

Operating expenses increased $29 million or 8% from 2003. This was due primarily to the addition of NUI operations for the month of December of $19 million. The remaining increase of $10 million was due to increases in the cost of outside services related to increased information technology services as a result of our ongoing implementation of a work management system, increased legal services due to increased regulatory activity and increased accounting services related to our implementation of SOX 404. Employee benefit and compensation expenses also increased primarily as a result of higher health care insurance costs and increased long-term compensation expenses. In addition, depreciation expenses increased primarily from new depreciation rates implemented for Virginia Natural Gas and increased assets at each utility. These increases were partially offset by a reduction in bad debt expenses, which was primarily due to a Tennessee Authority ruling that allows for recovery of the gas portion of accounts written off as uncollectible at Chattanooga Gas and increased collection efforts at both Chattanooga Gas and Virginia Natural Gas.

2003 Compared to 2002

EBIT increased $22 million or 10% for 2003 compared to 2002, primarily as a result of the gain, net of donation, of $13 million on the sale of our Caroline Street campus described above. Excluding the gain and donation, EBIT increased $9 million or 4% from increased operating margin, partially offset by increased operating expenses.

Operating margin increased $14 million or 2% from 2002. This was due primarily to an increased number of customers and a higher usage per degree day, of which Virginia Natural Gas contributed approximately $12 million. Atlanta Gas Light's PRP rider revenues increased $2 million, resulting from recovery of prior-year program expenses, and Atlanta Gas Light's carrying costs charged to Marketers for gas stored underground also contributed approximately $1 million due to higher storage volumes. Offsetting these increases was a reduction in Atlanta Gas Light's rates compared to prior year of $3 million for the first four months of 2003 due to the PBR settlement agreement with the Georgia Commission effective May 1, 2002. Chattanooga Gas' operating margin for 2003 was not materially different from 2002.

Operating expenses increased $4 million or 1% from 2002 due primarily to a $2 million increase in corporate allocated costs related to an increase in corporate building lease costs and higher general business insurance premiums. Bad debt expenses increased $2 million, primarily as a result of colder-than-normal weather and higher natural gas prices. Additional increases in operating expenses were attributed to a $1 million Virginia Natural Gas regulatory asset write-off in 2003. These increases in operating expenses were partially offset by a $1 million decrease in depreciation expenses due to lower depreciation rates at Atlanta Gas Light for the first four months of 2003 as a result of the PBR settlement agreement with the Georgia Commission.

WHOLESALE SERVICES

Wholesale services consists of Sequent, our subsidiary involved in asset optimization, transportation and storage, producer and peaking services, and wholesale marketing. Our asset optimization business focuses on capturing value from idle or underutilized natural gas assets, which are typically amassed by companies via investments in, or contractual rights to, natural gas transportation and storage assets. Margin is typically created in this business by participating in transactions that balance the needs of varying markets and time horizons.

Sequent provides its customers with natural gas from the major producing regions and market hubs primarily in the Eastern and Mid-Continental United States. Sequent also purchases transportation and storage capacity to meet its delivery requirements and customer obligations in the marketplace. Sequent's customers benefit from its logistics expertise and ability to deliver natural gas at prices that are advantageous relative to the other alternatives available to its end-use customers.

Asset Management Transactions

Our asset management customers include Atlanta Gas Light, Chattanooga Gas and Virginia Natural Gas, nonaffiliated utilities, municipal customers and industrial customers. These customers must contract for transportation and storage services to meet their demands, and they typically contract for these services on a 365-day basis even though they may only need a portion of these services to meet their peak demands for a much shorter period. We enter into agreements with these customers, either through contract assignment or agency arrangement, whereby we use their rights to transportation and storage services during periods when they do not need them. We capture margin by optimizing the purchase, transportation, storage and sale of natural gas, and we typically either share profits with customers or pay them a fee for using their assets. On April 1, 2005, in connection with the acquisition of NUI, Sequent plans to commence asset management responsibilities for Elizabethtown Gas, Florida Gas and Elkton Gas. The contract terms are currently being negotiated.

We have reached the following agreements with the Virginia, Georgia and Tennessee state regulatory commissions to clarify Sequent's role as asset manager for our regulated utilities. Failure to renew these agreements on terms substantially similar to the current terms would, over time, have a significant impact on Sequent's EBIT if other customers and assets were not found to replace our utility asset management earnings.

- In November 2000, the Virginia Commission approved an asset management agreement that provides for a sharing of profits between Sequent and Virginia Natural Gas customers. This agreement expires in October 2005, unless Sequent, Virginia Natural Gas and the Virginia Commission agree to extend the contract. In December 2004, we contributed approximately $3 million to Virginia Natural Gas customers for the contract year November 2003 through October 2004. This contribution is being reflected as a reduction to customers' gas cost in 2005. We commenced discussions as to mutually acceptable terms under which this agreement could be extended.
- Various Georgia statutes require Sequent, as asset manager for Atlanta Gas Light, to share 90% of its earnings from capacity release transactions with Georgia's Universal Service Fund (USF). A December 2002 Georgia Commission order requires net margin earned by Sequent, for transactions involving Atlanta Gas Light assets other than capacity release, to be shared equally with the USF. Sequent operates under an asset management agreement with Atlanta Gas Light which is currently scheduled to expire in March 2006. In 2004, we contributed approximately $4 million to the USF based on profits earned in the last six months of 2003 and for the first six months of 2004.
- In June 2003, the Chattanooga Gas tariff was amended effective January 1, 2003 to require all net margin earned by Sequent for transactions involving Chattanooga Gas assets to be shared equally with Chattanooga Gas ratepayers. This agreement expires in April 2006 and is subject to automatic extensions unless specifically terminated by either party. In 2004, Sequent contributed approximately $1 million to Chattanooga Gas customers based on profits earned in 2003. This contribution was reflected as a reduction to customers' gas cost in 2004.

Transportation and Storage Transactions

In our wholesale marketing and risk management business, Sequent also contracts for transportation and storage services. We participate in transactions to manage the natural gas commodity and transportation costs that result in the lowest cost to serve our various markets. We seek to optimize this process on a daily basis, as market conditions change, by evaluating all the natural gas supplies, transportation and markets to which we have access and identifying the least-cost alternatives to serve our various markets. This enables us to capture geographical pricing differences across these various markets as delivered gas prices change.

In a similar manner, we participate in natural gas storage transactions where we seek to identify pricing differences that occur over time as prices for future delivery periods at many locations are readily available. We capture margin by locking in the price differential between purchasing natural gas at the lowest future price and, in a related transaction, selling that gas at the highest future price, all within the constraints of our contracts. Through the use of transportation and storage services, we are able to capture margin through the arbitrage of geographical pricing differences and by recognizing pricing differences that occur over time.

Producer Services

Our producer services business primarily focuses on aggregating natural gas supply from various small and medium-sized producers located throughout the natural gas production areas of the United States, principally in the Gulf Coast region. We provide the producers certain logistical and risk management services that offer them attractive options to move their supply into the pipeline grid. Aggregating volumes of natural gas from these producers allows us to provide markets to producers who seek a reliable outlet for their natural gas production.

Peaking Services

Wholesale services generates operating margin through, among other things, the sale of peaking services, which includes receiving a fee from affiliated and nonaffiliated customers that guarantees that those customers will receive gas under peak conditions. Wholesale services incurs costs to support our obligations under these agreements, which will be reduced in whole or in part as the matching obligations expire. We will continue to seek new peaking transactions as well as work toward extending those that are set to expire.

Competition

Sequent competes for asset management business with other energy wholesalers, often through a competitive bidding process. Sequent has historically been successful in obtaining new asset management business by placing bids that were based primarily on the intrinsic value of the transaction, which is the difference in commodity prices between time periods or locations at the inception of the transaction.

There has been significant consolidation of energy wholesale operations, particularly among major gas producers. Financial institutions have also entered the marketplace. As a result, energy wholesalers have become increasingly willing to place bids for asset management transactions that are priced to capture market share. We expect this trend to continue in the near term, which could result in downward pressure on the volume of transactions and the related margins available in this portion of Sequent's business.

Business Expansion

Sequent has been focusing on expanding its business, both geographically and through added emphasis on the origination of new asset management transactions and growing the producer services businesses. Throughout 2004, we added personnel to focus specifically on these opportunities and continued to execute additional nonaffiliated asset management transactions. Our business territory now extends from Texas to Michigan and most other areas of the United States east of the Mississippi River.

This expansion, as well as our other business growth, has increased Sequent's fixed cost commitments in the form of firm capacity charges for transportation and storage contracts and has lengthened the average tenure of our portfolio to 25 months at December 31, 2004. At December 31, 2004, Sequent's longest-dated contract in its portfolio was 23 years and was obtained as part of the NUI acquisition. Excluding this contract, Sequent's portfolio contains transactions with contract terms ranging from one day to eight years. At December 31, 2004, Sequent's firm capacity commitments were:

In millions	Contract from NUI Acquisition	Other	Total
2005	$ 5	$8	$ 13
2006	5	2	7
2007 and thereafter	107	9	116

Seasonality

Fixed cost commitments are generally incurred evenly over the year, while margins generated through the use of these assets are generally greatest in the winter heating season and occasionally in the summer due to peak usage by power generators in meeting air conditioning load. This increases the seasonality of our business, generally resulting in expected higher margins in the first and fourth quarters.

Business Outlook

Continued growth of the nonaffiliated asset management and producer services business lines will be critical to Sequent's success in 2005. Despite the consolidations within the industry, many entities are reluctant to turn over the marketing of their gas or their assets to a major competitor and may favor an independent wholesale services provider. In addition, many utilities are seeking incremental services to meet peak-day needs, which is an area of core expertise for Sequent.

We manage our business with limited open positions and limited value at risk (VaR). However, the rescission of Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10), and our adoption of EITF Issue No. 02-03, "Issues Involved in Accounting for Contracts under EITF Issue No. 98-10, 'Accounting for Contracts Involved in Energy Trading and Risk Management Activities'" (EITF 02-03), in 2003 have increased earnings volatility in our reported results, as more fully discussed below. Given significant underlying volatility in gas commodity prices, we expect volatility in our earnings to continue.

Energy Marketing and Risk Management Activities

We accounted for derivative transactions in connection with our energy marketing activities on a fair value basis in accordance with Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133), and prior to 2003 we accounted for nonderivative energy and energy-related activities in accordance with EITF 98-10.

Under these methods, we recorded derivative energy commodity contracts (including both physical transactions and financial instruments) at fair value, with unrealized gains or losses from changes in fair value reflected in our earnings in the period of change. We also recorded energy-trading contracts, as defined under EITF 98-10, on a mark-to-market basis for transactions executed on or before October 25, 2002. Energy-trading contracts entered into after October 25, 2002 were recorded on an accrual basis as required under the EITF 02-03 rescission of EITF 98-10, unless they were derivatives that must be recorded at fair value under SFAS 133.

Effective January 1, 2003, we adopted EITF 02-03 (which rescinded EITF 98-10), which had the following effects:

- Contracts that do not meet the definition of a derivative under SFAS 133 are not marked to fair market value.
- Revenues are shown in the income statement net of costs associated with trading activities, whether or not the trades are physically settled.

As a result of our adoption of EITF 02-03:

- We recorded an adjustment to the carrying value of our nonderivative trading instruments (principally our storage capacity contracts) to zero, and we now account for them using the accrual method of accounting.
- We recorded an adjustment to the value of our natural gas inventories used in wholesale services to the lower of average cost or market; we previously recorded them at fair value. This resulted in the cumulative effect of a change in accounting principle in our statement of consolidated income for the three months ended March 31, 2003 of $13 million ($8 million net of taxes), which resulted in a decrease of $13 million to our energy marketing and risk management assets, and a decrease in accumulated deferred income taxes of $5 million in our accompanying consolidated balance sheet.
- We reclassified our trading activity on a net basis (revenues net of costs) effective July 1, 2002 as a result of the first consensus of EITF 02-03. This reclassification had no impact on our previously reported net income or shareholders' equity. Revenues for all periods are shown net of costs associated with trading activities.

As shown in the table below, Sequent recorded net unrealized gains related to changes in the fair value of derivative instruments utilized in our energy marketing and risk management activities of $22 million during 2004, $1 million during 2003 and $4 million in 2002. The tables below illustrate the change in the net fair value of the derivative instruments and energy-trading contracts during 2004, 2003 and 2002 and provide details of the net fair value of contracts outstanding as of December 31, 2004. Sequent's storage positions are affected by price sensitivity in the New York Mercantile Exchange (NYMEX) average price.

In millions	2004	2003	2002
Net fair value of contracts outstanding at beginning of period	$ (5)	$ 7	$ 3
Cumulative effect of change in accounting principle	—	(13)	—
Net fair value of contracts outstanding at beginning of period, as adjusted	(5)	(6)	3
Contracts realized or otherwise settled during period	11	2	(5)
Change in net fair value of contract gains (losses)	11	(1)	9
Net fair value of new contracts entered into during period	—	—	—
Net fair value of contracts outstanding at end of period	17	(5)	7
Less net fair value of contracts outstanding at beginning of period, as adjusted for cumulative effect of change in accounting principle	(5)	(6)	3
Unrealized gain related to changes in the fair value of derivative instruments	$22	$ 1	$ 4

The sources of our net fair value at December 31, 2004 are as follows. The "prices actively quoted" category represents Sequent's positions in natural gas, which are valued exclusively using NYMEX futures prices. "Prices provided by other external sources" are basis transactions that represent the cost to transport the commodity from a NYMEX delivery point to the contract delivery point. Our basis spreads are primarily based on quotes obtained either directly from brokers or through electronic trading platforms.

In millions	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Net Fair Value
Prices actively quoted	$ 6	$ 1	$—	$—	$ 7
Prices provided by other external sources	$10	$—	$—	$—	$10

Mark-to-market Versus Lower of Average Cost or Market

We purchase gas for storage when the current market price we pay for gas plus the cost to store the gas is less than the market price we could receive in the future. We attempt to mitigate substantially all of our commodity price risk associated with our gas storage portfolio. We use derivative instruments to reduce the risk associated with future changes in the price of natural gas. We sell NYMEX futures contracts or other over-the-counter derivatives in forward months to substantially lock in the profit margin we will ultimately realize when the stored gas is actually sold.

Gas stored in inventory is accounted for differently than the derivatives we use to mitigate the commodity price risk associated with our storage portfolio. The difference in accounting can result in volatility in our reported net income, even though the profit margin is essentially unchanged from the date the transactions were consummated. Gas that we purchase and inject into storage is accounted for at the lower of average cost or market. The derivatives we use to mitigate commodity price risk are accounted for at fair value and marked to market each period. These differences in our accounting treatment, including the accrual basis for our gas storage inventory versus fair value accounting for the derivatives used to mitigate commodity price risk, can result in volatility in our reported earnings.

Earnings Volatility and Price Sensitivity

Over time, gains or losses on the sale of gas storage inventory will be offset by losses or gains on the derivatives used as hedges, resulting in the realization of the profit margin we expected when we entered into the transactions. Accounting differences cause Sequent's earnings on its gas storage positions to be affected by natural gas price changes, even though the economic profits remain essentially unchanged. Based on our storage positions at December 31, 2004, a $0.10 change in the forward NYMEX prices would result in a $0.3 million impact to Sequent's EBIT. As Sequent's storage position increases, its earnings volatility may also increase. For example, at year end, if all of Sequent's storage had been full, a $0.10 change in forward NYMEX prices would have resulted in a $0.7 million impact to its earnings.

In addition, if we were to value the gas inventory at fair value, with the change in fair value during the year reflected in earnings, Sequent's EBIT would have increased, net of applicable regulatory sharing, by $1 million and $3 million for the years ended December 31, 2004 and 2003. This is based on a difference between fair value and average cost of $2 million and $5 million for 2004 and 2003. We used a calculation to compare the forward value using market prices at the expected withdrawal period with the cost of inventory included in the balance sheet to determine fair value. The fair value is not reflected in the financial statements due to the accounting rules now in effect.

Storage Inventory Outlook

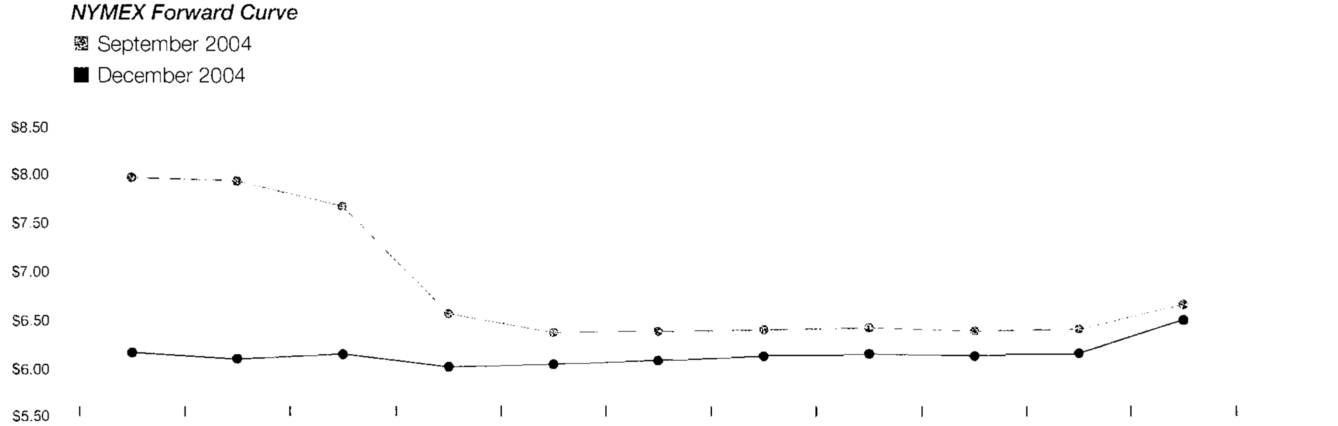
The NYMEX forward curve graph set forth below reflects the NYMEX natural gas prices as of September 30, 2004 and December 31, 2004 for the period of January 2005 through November 2005. The curve reflects the prices at which we could buy natural gas at the Henry Hub for delivery in the same time period. (Note: January 2005 futures expired on December 28, 2004; however, they are included as they coincide with the January storage withdrawals.) The Henry Hub, located in Louisiana, is the largest centralized point for natural gas spot and futures trading in the United States. NYMEX uses the Henry Hub as the point for delivery for its natural gas futures contracts. Many natural gas marketers also use the Henry Hub as their physical contract delivery point for their price benchmark for spot trades of natural gas.

The NYMEX forward curve graph also displays the significant decline in first quarter 2005 NYMEX prices experienced during the fourth quarter of 2004. As shown in the table following the graph, the majority of our inventory in storage as of December 31, 2004 was scheduled for withdrawal in early 2005. Since we have these NYMEX contracts in place, our original economic profit margin is unaffected. However, the decline in NYMEX prices during the fourth quarter of 2004 resulted in unrealized gains associated with our NYMEX contracts. During the fourth quarter of 2003, we experienced the opposite occurrence when NYMEX prices were increasing. In 2003, our near-term profits declined because our future-period hedges were at values lower than the prevailing market prices for the months in which we held the NYMEX contracts. See further discussions in "Results of Operations" below.

As shown in the table below, "Open Futures NYMEX Contracts" represents the volume in contract equivalents of the transactions we executed to lock in our storage inventory margin. Each contract equivalent represents 10,000 million British thermal units (MMBtu's). As of December 31, 2004, the expected withdrawal schedule of this inventory is reflected in items (B) and (C). At December 31, 2004, the weighted average cost of gas (WACOG) in salt dome storage was $5.83, and the WACOG for gas in reservoir storage was $5.88.

The table also reflects that our storage inventory is fully hedged with futures, which results in an overall locked-in margin, timing notwithstanding. Expected gross margin after regulatory sharing reflects the gross margin we would generate in future periods based on the forward curve and inventory withdrawal schedule at December 31, 2004. Our current inventory level and pricing will result in gross margin of $1 million during 2005. This gross margin could change if we adjust our daily injection and withdrawal plans in response to changes in market conditions in future months.

NYMEX Forward Curve



	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Total
A	(21)	(105)	(286)	—	—	—	—	—	(2)	(10)	—	(424)
B	4	—	—	—	—	—	—	—	—	—	—	4
C	17	105	286	—	—	—	—	—	2	10	—	420
	21	105	286	—	—	—	—	—	2	10	—	424
D	$0.1	$0.2	$0.8	$—	$—	$—	$—	$—	$—	$—	$—	$1.1

A Open futures NYMEX contracts (short) long (in MMBtu).

B Physical salt dome withdrawal schedule (in MMBtu).

C Physical reservoir withdrawal schedule (in MMBtu).

D Expected gross margin, in millions, after regulatory sharing for withdrawal activity.

Park and Loan Outlook

Additionally, we have entered into park and loan transactions with various pipelines. A park and loan transaction is a tariff transaction offered by pipelines in which the pipeline allows the customer to park gas on or borrow gas from the pipeline in one period and reclaim gas from or repay gas to the pipeline in a subsequent period. The economics of these transactions are evaluated and price risks are managed similar to the way traditional reservoir and salt dome storage transactions are evaluated and managed. Sequent enters into forward NYMEX contracts to hedge its park and loan transactions. However, these transactions have elements that qualify as and must be accounted for as derivatives in accordance with SFAS 133.

Under SFAS 133, park and loan transactions are considered to be financing arrangements when the contracts contain volumes that are payable or repaid at determinable dates and at a specific time to third parties. Because these park and loan transactions have fixed volumes, they contain price risk for the change in market prices from the date the transaction is initiated to the time the gas is repaid. As a result, these transactions qualify as derivatives under SFAS 133 that must be recorded at their fair value. Certain park and loan transactions that we execute meet this definition. As such, we account for these transactions at fair value once the transaction has started (either the gas is originally parked on or borrowed from the pipeline) and represent the fair value of the derivatives in the consolidated balance sheet as "Inventories" and reflect the related changes in fair value in our statement of consolidated income.

The table below shows Sequent's park and loan volumes and expected gross margin from park and loans for the indicated periods. "Park and (loan) volumes" represents the contract equivalent for the volumes of our park and loan transactions as of December 31, 2004 that is not already accounted for at fair value. "Expected gross margin from park and loans" represents the gross margin from those transactions expected to be recognized in future periods based on the NYMEX forward curves at December 31, 2004.

In millions	Jan 2005	Feb 2005	Mar 2005	Apr 2005	May 2005	Jun 2005	Jul 2005	Total
Park and (loan) volumes (MMBtu)	(15)	12	6	—	15	(12)	(6)	—
Expected gross margin from park and (loans)	$(0.3)	$0.3	$0.1	—	—	—	—	$0.1

Credit Rating

Sequent has certain trade and credit contracts that have explicit rating trigger events in case of a credit rating downgrade. These rating triggers typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, we would need to post collateral to continue transacting business with some of our counterparties. Posting collateral would have a negative effect on our liquidity. If such collateral were not posted, our ability to continue transacting business with these counterparties would be impaired. If at December 31, 2004, our credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $20 million.

Results of Operations for our wholesale services segment for the years ended December 31, 2004, 2003 and 2002 are as follows:

In millions	2004	2003	2002	2004 vs. 2003	2003 vs. 2002
Operating revenues	**$54**	$41	$23	$13	$18
Cost of sales	**1**	1	—	—	1
Operating margin	**53**	40	23	13	17
Operation and maintenance expenses	**27**	20	13	7	7
Depreciation and amortization	**1**	—	—	1	—
Taxes other than income	**1**	—	1	1	(1)
Total operating expenses	**29**	20	14	9	6
Operating income	**24**	20	9	4	11
Other loss	**—**	—	—	—	—
EBIT	**$24**	$20	$ 9	$ 4	$11
Metrics					
Physical sales volumes (Bcf/day)	**2.10**	1.75	1.39	20%	26%

2004 Compared to 2003
EBIT increased $4 million or 20% from 2003 due to a $13 million increase in operating margin, partially offset by a $9 million increase in operating expenses.

Operating margin increased by $13 million or 33% primarily due to increased volatility during the fourth quarter of 2004, which provided Sequent with seasonal trading, marketing, origination and asset management opportunities in excess of those experienced during the prior year. Also contributing to the increase were advantageous transportation values to the Northeast and new peaking and third-party asset management transactions. Sequent's sales volumes for 2004 were 2.10 Bcf/day, a 20% increase from the prior year. This increase resulted primarily from the addition of new counterparties, increased presence in the Midwest and Northeast markets and continued growth in origination and asset management activities, as well as the business generated due to the market volatility experienced during the fourth quarter.

As a result of a decline in forward NYMEX prices, the 2004 results reflect the recognition of gains associated with the financial instruments used to hedge Sequent's inventory held in storage. If the forward NYMEX price in effect at December 1, 2004 had also been in effect at December 31, 2004, based on Sequent's storage positions at December 31, 2004, Sequent's reported EBIT would have been $19 million. At December 31, 2003, an increase in forward NYMEX prices resulted in the recognition of losses associated with inventory hedges.

Partially offsetting the improved fourth-quarter results was lower volatility during the second quarter of 2004 compared to the same period in 2003, which compressed Sequent's trading and marketing activities and the related margins within its transportation portfolio. In addition, Sequent's weighted average cost of natural gas stored in inventory was $5.06 per MMBtu during the first quarter of 2004 compared to $2.20 per MMBtu during the same period in 2003. This significant difference in cost resulted in reduced operating margins period over period.

Operating expenses increased by $9 million or 45% due primarily to additional salary expense as a result of an increase in the number of employees; additional costs for outside services related to the development and implementation of Sequent's ETRM system; the implementation of SOX 404; and increased corporate costs. In addition, 2004 operating expenses reflect depreciation associated with the recently implemented ETRM system.

2003 Compared to 2002
EBIT increased $11 million or 122% from 2002 primarily due to a $17 million increase in operating margin, offset by an increase of $6 million in operating expenses. The increase of $17 million or 74% in operating margin was due primarily to Sequent's optimization of various transportation and storage assets, mainly in the first quarter when natural gas prices were highly volatile. Sequent's physical sales volumes for 2003 increased 26% to 1.75 Bcf/day compared to 2002. This increase was partially attributable to Sequent's successful efforts to gain additional new business in the Midwest and Northeast. Additionally, a number of market factors, including colder temperatures during the winter in market areas served by Sequent and reduced amounts of gas in storage as the winter progressed, resulted in increased volatility in Sequent's markets during the first quarter of 2003 compared to the same period of 2002. The volatility in the second and third quarters returned to seasonal averages and increased slightly above average in the fourth quarter.

In the first quarter, Sequent sold substantially all its inventory that was previously recorded on a mark-to-market basis under the now-rescinded EITF 98-10. This resulted in $13 million in realized income, offset by amounts shared with our affiliated local distribution companies for transactions that were recorded on a mark-to-market basis in prior periods. The increase in operating margin was partly offset by lower natural gas volatility created by unseasonably cool temperatures in the Southeast, Midwest and Upper Mid-Atlantic during the summer of 2003. In the summer of 2002, volatility was higher as a result of two hurricanes in the Gulf of Mexico and warmer-than-normal temperatures in the Northeast.

Operating expenses increased by $6 million or 43%, primarily due to a $3 million increase in corporate costs and a $3 million increase primarily due to personnel and outside consulting costs incurred while growing the business.

ENERGY INVESTMENTS

Our energy investments segment includes

SouthStar is a joint venture formed in 1998 by our subsidiary, Georgia Natural Gas Company, Piedmont and Dynegy Inc. (Dynegy) to market natural gas and related services to retail customers, principally in Georgia. On March 11, 2003, we purchased Dynegy's 20% ownership interest in a transaction that for accounting purposes had an effective date of February 18, 2003.

We currently own a noncontrolling 70% financial interest in SouthStar, and Piedmont owns the remaining 30%. Our 70% interest is noncontrolling because all significant management decisions require approval of both owners. On March 29, 2004, we executed an amended and restated partnership agreement with Piedmont. This amended and restated partnership agreement calls for SouthStar's future earnings starting in 2004 to be allocated 75% to our subsidiary and 25% to Piedmont. In addition, we executed a services agreement which provided that AGL Services Company (AGL Services) will provide and administer accounting, treasury, internal audit, human resources and information technology functions for SouthStar.

Competition SouthStar, which operates under the trade name Georgia Natural Gas, competes with other energy marketers, including Marketers in Georgia, to provide natural gas and related services to customers in Georgia and the Southeast. Based on its market share, SouthStar is the largest retail marketer of natural gas in Georgia with average customers in 2004 in excess of 500,000. This represents a market share of approximately 36% as of December 31, 2004, which is consistent with its market share in 2003 and 2002.

Pivotal Jefferson Island, our wholly owned subsidiary, operates a storage and hub facility in Louisiana, approximately eight miles from the Henry Hub. We acquired the facility from American Electric Power in October 2004 for an adjusted price of $90 million, which included approximately $9 million of working gas inventory. We funded the acquisition with a portion of the net proceeds we received from our November 2004 common stock offering and debt borrowings.

The storage facility is regulated by the Louisiana Public Service Commission and by the FERC, the latter of which regulates the storage and transportation services. The facility consists of two salt dome gas storage caverns with 9.4 million Dth of total capacity and about 6.9 million Dth of working gas capacity. By increasing the maximum operating pressure, we can periodically increase the working gas capacity to approximately 7.4 million Dth. The facility has approximately 720,000 Dth/day withdrawal capacity and 240,000 Dth/day injection capacity. Pivotal Jefferson Island provides for storage and hub services through its direct connection to the Henry Hub via the Sabine Pipeline and its interconnection with other pipelines in the area. Pivotal Energy Development (Pivotal Development) is responsible for the day-to-day operation of the facility.

Pivotal Jefferson Island is fully subscribed for the 2004–2005 winter period. Beginning April 1, 2005, approximately 2.5 Bcf of capacity will become available. Marketing of this capacity is ongoing. Pivotal Jefferson Island intends to lease any unsubscribed capacity to one or more customers in 2005, for varying term lengths to create a portfolio of contracts for service. Pivotal Jefferson Island is currently expanding its compression capability to enhance the number of times a customer can inject and withdraw gas. We expect to complete this upgrade in the third quarter of 2005.

Pivotal Propane of Virginia, Inc. (Pivotal Propane), our wholly owned subsidiary, intends to complete in the first quarter of 2005 the construction of a propane-air facility in the Virginia Natural Gas service area to provide it with up to 28,800 Dth of propane air per day on a 10-day-per-year basis to serve Virginia Natural Gas' peaking needs. The cold storage tank foundation is complete and construction of the process facility is under way. We expect the plant to be initially available in the first quarter of 2005.

Virginia Gas Company is a natural gas storage, pipeline and distribution company with principal operations in southwestern Virginia. Virginia Gas Company, through its wholly owned subsidiary Virginia Gas Pipeline Co., owns and operates a 72-mile intrastate pipeline and operates two storage facilities, a high-deliverability salt cavern facility, Saltville Storage Inc. (Saltville Storage) in Saltville, Virginia, and a depleted reservoir facility in Early Grove, Virginia. Combined, the storage facilities have approximately 2.6 Bcf of working gas capacity. Virginia Gas Pipeline Co. also serves as construction and operations manager for our Saltville Storage joint venture described below.

Saltville Storage is a 50% member of Saltville Gas Storage Company, LLC, a joint venture formed in 2001 with a subsidiary of Duke Energy Corporation (Duke) to develop a high-deliverability natural gas storage facility in Saltville, Virginia and is accounted for under the equity method of accounting. Saltville Storage serves customers in the Mid-Atlantic region. Saltville Storage currently has approximately 1.8 Bcf of storage capacity and is planning an expansion to increase its storage capacity to 5.3 Bcf of working gas with deliverability of up to 500 million cubic feet per day. The expansion is expected to be completed in 2008. Saltville Storage connects to Duke's East Tennessee Natural Gas interstate system and its Patriot pipeline.

All of Virginia Gas Company's businesses are regulated by the Virginia Commission except Saltville Storage, which is regulated by the FERC. As such, Saltville Storage is required to construct and operate its facilities and provide service subject to FERC regulations.

AGL Networks, our wholly owned subsidiary, is a provider of telecommunications conduit and dark fiber. AGL Networks leases and sells its fiber to a variety of customers in the Atlanta, Georgia and Phoenix, Arizona metropolitan areas, with a small presence in other cities in the United States. Its customers include local, regional and national telecommunications companies, internet service providers, educational institutions and other commercial entities. AGL Networks typically provides underground conduit and dark fiber to its customers under leasing arrangements with terms that vary from 1 to 20 years. In addition, AGL Networks offers telecommunications construction services to companies.

Competition AGL Networks' competitors exist to the extent that they have, or will lay, conduit and fiber or may install conduit in the future on the same route in the respective metropolitan areas. We believe our conduit and dark fiber footprints in Atlanta and Phoenix are unique continuous rings and, as such, will be subscribed ahead of most competitors as market conditions support greater use of our product.

US Propane is a joint venture formed in 2000 by us, Atmos Energy Corporation, Piedmont and TECO Energy, Inc. US Propane owned all the general partnership interests, directly or indirectly, and approximately 25% of the limited partnership interests in Heritage Propane Partners, L.P. (Heritage Propane), a publicly traded marketer of propane. On January 20, 2004, we sold our general and limited partnership interests for $29 million and recognized a gain of $1 million, which we recorded in other income.

Results of Operations for our energy investments segment for the year ended December 31, 2004, and pro-forma results as if SouthStar's accounts were consolidated with our subsidiaries' accounts for the years ended December 31, 2003 and 2002 are set forth below. The unaudited pro-forma results are presented for comparative purposes as a result of our consolidation of SouthStar in 2004. This pro-forma basis is a non-GAAP presentation; however, we believe it is useful to the readers of our financial statements since it presents prior years' revenue and expenses on the same basis as 2004.

In 2003 and 2002, we recognized our portion of SouthStar's earnings of $46 million and $27 million, respectively, as equity earnings. The increase of $19 million or 70% was primarily due to resolution of an income sharing issue with Piedmont of $6 million, higher volumes and related operating margin, an additional 20% ownership interest (which contributed approximately $8 million), and lower bad debt and operating expenses.

In millions	2004	Pro-forma 2003	Pro forma 2002	2004 vs. 2003	2003 vs. 2002
Operating revenues	**$852**	$752	$632	$100	$120
Cost of sales	**707**	622	515	85	107
Operating margin	**145**	130	117	15	13
Operation and maintenance expenses	**65**	69	80	(4)	(11)
Depreciation and amortization	**4**	2	2	2	—
Taxes other than income	**1**	1	—	—	1
Total operating expenses	**70**	72	82	(2)	(10)
Operating income	**75**	58	35	17	23
Other income	**2**	2	4	—	(2)
Minority interest	**(18)**	(17)	(15)	(1)	(2)
EBIT	**$ 59**	$ 43	$ 24	$ 16	$ 19

Metrics					
SouthStar					
Average customers (in thousands)	**533**	558	564	(4)%	(1)%
Market share in Georgia	**36%**	38%	38%	(5)%	—

2004 Compared to 2003

The increase in EBIT of $16 million or 37% for the year ended December 31, 2004 was primarily the result of increased EBIT of $7 million from SouthStar, EBIT of $3 million from Pivotal Jefferson Island and EBIT of $3 million from AGL Networks. The remaining increase of $3 million was from the sale of Heritage Propane and the sale of a residential and retail development property in Savannah, Georgia in the second quarter of 2004.

Operating margin for the year increased $15 million or 12% primarily as a result of operating margin increases at SouthStar of $8 million, the addition of Pivotal Jefferson Island's $4 million of operating margin and an operating margin increase at AGL Networks of $4 million. SouthStar's $8 million operating margin increase was a result of a $9 million increase due primarily to a lower commodity cost structure resulting from continued refinement of SouthStar's hedging strategies and a $3 million increase due to a full year of higher customer service charges from third-party providers. These increases were partially offset by a decrease of $2 million related to a one-time sale of stored gas in 2003 and a $2 million decrease in late payment fees due to an improved customer base. AGL Networks' increase was due to increased revenue from a variety of customers.

Operating expenses decreased by $2 million or 3% primarily due to $6 million lower bad debt expense as a result of ongoing active customer collection process improvements and increased quality of the customer base partially offset by a $5 million increase in corporate allocations and increased costs related to SOX 404 implementation. There was also a $1 million increase in minority interest as a result of higher SouthStar earnings in 2004 compared to 2003.

2003 Compared to 2002

The EBIT increase of $19 million or 79% was primarily due to increased EBIT at SouthStar and US Propane, offset by lower AGL Networks earnings.

Operating margin increased $13 million or 11% primarily due to $9 million from increased margin from SouthStar resulting from a $3 million one-time sale of storage, a $3 million increase from higher customer service charges and a $3 million increase in additional interruptible margin. There was also a $4 million increase in margin from AGL Networks due to a $3 million increase in monthly recurring contract revenues and a $2 million sales-type lease completed in the first quarter of 2003, partially offset by $1 million of feasibility fee income in 2002; no such fees were recognized in 2003.

The decrease in operating expenses of $10 million or 12% was due primarily to lower bad debt expense at SouthStar of $10 million as a result of improved delinquency processes and customer base and lower operating expenses from a reduction in customer care costs of $3 million. AGL Networks had a $3 million increase in operating expenses due primarily to business growth and higher corporate overhead costs. Other income decreased $2 million due primarily to a contract renewal payment of $2 million associated with the sale of Utilipro.

CORPORATE

Our corporate segment includes our nonoperating business units, including AGL Services and AGL Capital Corporation (AGL Capital). AGL Services is a service company established in accordance with the Public Utility Holding Company Act of 1935, as amended (PUHCA). AGL Capital provides for our ongoing financing needs through its commercial paper program, the issuance of various debt and hybrid securities, and other financing arrangements.

In August 2003, we formed Pivotal Development as an operating division within AGL Services. Pivotal Development coordinates, among our related operating segments, the development, construction or acquisition of gas-related assets in the regions our gas utilities serve or where their gas supply originates in order to extend our natural gas capabilities and improve system reliability while enhancing service to our customers in these areas. The focus of Pivotal Development's commercial activities is to improve the economics of system reliability and natural gas deliverability in these regions as well as acquire and operate natural gas assets that serve wholesale markets, such as underground storage.

We allocate substantially all AGL Services' and AGL Capital's operating expenses and interest costs to our operating segments in accordance with the PUHCA and state regulations. Our corporate segment also includes intercompany eliminations for transactions between our operating business segments.

Results of Operations for our corporate segment for the years ended December 31, 2004, 2003 and 2002 are as follows:

In millions	2004	2003	2002	2004 vs. 2003	2003 vs. 2002
Payroll	**$ 48**	$ 48	$ 44	$ —	$ 4
Benefits and incentives	**32**	32	38	—	(6)
Outside services	**29**	19	21	10	(2)
Taxes other than income	**4**	2	4	2	(2)
Other	**46**	44	35	2	9
Total operating expenses before allocations	**159**	145	142	14	3
Allocation to operating segments	**(147)**	(139)	(134)	(8)	(5)
Operating expenses	**12**	6	8	6	(2)
Loss on asset disposed of Caroline Street campus	**—**	(5)	—	5	(5)
Operating loss	**(12)**	(11)	(8)	(1)	(3)
Other losses	**(4)**	(1)	(3)	(3)	2
EBIT	**$ (16)**	$ (12)	$ (11)	$ (4)	$(1)

2004 Compared to 2003

The decrease in EBIT of $4 million or 33% for the year ended December 31, 2004 compared to the same period last year primarily was due to an increase in operating expenses of $6 million. The increase in operating expenses was primarily from increased outside services costs associated with software maintenance, licensing and implementation of our work management system project, higher costs due to our SOX 404 compliance efforts, merger and acquisition related expenses and expenses related to Pivotal Development's activities in 2004. The increase in operating expenses was offset by a loss of $5 million on the sale of our Caroline Street campus in 2003.

2003 Compared to 2002

The decrease in EBIT of $1 million or 9% for 2003 compared to 2002 was primarily the result of a loss of $5 million on the sale of our Caroline Street campus. The decrease was offset by decreased operating expenses of $2 million for 2003 compared to 2002.

The $2 million decrease in operating expenses was due to charges incurred in 2002 that were not incurred in 2003. In 2002, we recorded $6 million for the termination of an automated meter reading contract, $2 million for the write-off of capital costs related to a terminated risk management software implementation project and $2 million in employee severance costs. These decreases in operating expenses were offset by an $8 million increase in operating expenses consisting primarily of higher payroll due to the transfer of call center employees to AGL Services from distribution operations, and the increase in facility lease expense as a result of our headquarters move in 2003.

LIQUIDITY AND CAPITAL RESOURCES

We rely on operating cash flow; short-term borrowings under our commercial paper program, which is backed by our supporting credit agreement (Credit Facility); and borrowings or stock issuances in the long-term capital markets to meet our capital and liquidity requirements. We believe these sources will be sufficient for our working capital needs, including the potentially significant volatility of working capital requirements of our wholesale services business, debt service obligations and scheduled capital expenditures for the foreseeable future. The relatively stable operating cash flows of our distribution operations business currently provide most of our cash flow from operations, and we anticipate this to continue in the future. However, we have historically had a working capital deficit, primarily as a result of our borrowings of short-term debt to finance the purchase of long-term assets, principally property, plant and equipment, and we expect this to continue in the future. Our liquidity and capital resource requirements may change in the future due to a number of factors, some of which we cannot control. These factors include

- the seasonal nature of the natural gas business and our resulting short-term borrowing requirements, which typically peak during colder months
- increased gas supplies required to meet our customers' needs during cold weather
- changes in wholesale prices and customer demand for our products and services
- regulatory changes and changes in rate-making policies of regulatory commissions

- contractual cash obligations and other commercial commitments
- interest rate changes
- pension and postretirement benefit funding requirements
- changes in income tax laws
- margin requirements resulting from significant increases or decreases in our commodity prices
- operational risks

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies, including state public service commissions and the SEC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operation of regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. On April 1, 2004, we received approval from the SEC, under the PUHCA, for the renewal of our financing authority to issue securities through April 2007. Our total cash and available liquidity under our Credit Facility at December 31, 2004 and 2003 is represented in the table below:

In millions	Dec 31, 2004	Dec 31, 2003
Unused availability under the Credit Facility	**$750**	$500
Cash and cash equivalents	**49**	17
Total cash and available liquidity under the Credit Facility	**$799**	$517

The increase in total cash and available liquidity under our Credit Facility of $282 million is due primarily to the amendment to our Credit Facility in September 2004 that, among other things, increased the facility size by $250 million, and additional cash from operations at December 31, 2004.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

We have incurred various contractual obligations and financial commitments in the normal course of our operations and financing activities. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease arrangements that are directly supported by related revenue-producing activities. We calculate any expense pension contributions using an actuarial method called the projected unit credit cost method, and as a result of our calculations, we expect to make a $1 million pension contribution in 2005. The table below illustrates our expected future contractual obligations:

		Payments Due Before December 31,			
In millions	Total	2005	2006 & 2007	2008 & 2009	2010 & Thereafter
Long-term debt[1,2]	$1,623	$ —	$ 2	$ 2	$1,619
Pipeline charges, storage capacity and gas supply[3,4]	1,051	258	262	179	352
Short-term debt[2]	334	334	—	—	—
PRP costs[5]	327	85	162	80	—
Operating leases[6]	170	27	39	29	75
ERC[5]	90	27	10	12	41
Commodity and transportation charges	20	19	1	—	—
Total	$3,615	$750	$476	$302	$2,087

[1] Includes $232 million of notes payable to Trusts redeemable in 2006 and 2007.

[2] Does not include the interest expense associated with the long-term and short-term debt.

[3] Charges recoverable through a PGA mechanism or alternatively billed to Marketers. Also includes demand charges associated with Sequent.

[4] A subsidiary of NUI entered into two 20-year agreements for the firm transportation and storage of natural gas during 2003 with the annual demand charges aggregate of approximately $5 million. As a result of our acquisition of NUI and in accordance with SFAS 141, "Business Combinations," the contracts were valued at fair value. The $38 million currently allocated to accrued pipeline demand charges on our consolidated balance sheets represent our estimate of the fair value of the acquired contracts. The liability will be amortized over the remaining lives of the contracts.

[5] Charges recoverable through rate rider mechanisms.

[6] We have certain operating leases with provisions for step rent or escalation payments, or certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with SFAS No. 13, "Accounting for Leases" (SFAS 13). However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein.

SouthStar has natural gas purchase commitments related to the supply of minimum natural gas volumes to its customers. These commitments are priced on an index plus premium basis. At December 31, 2004, SouthStar had obligations under these arrangements for 11.2 Bcf for the year ended December 31, 2005. This obligation is not included in the above table. SouthStar also had capacity commitments related to the purchase of transportation rights on interstate pipelines.

We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The following table illustrates our expected contingent financial commitments as of December 31, 2004:

			Commitments Due Before December 31,		
In millions	Total	2005	2006 & 2007	2008 & 2009	2010 & Thereafter
Guarantees*	$ 7	$ 7	$—	$—	$—
Standby letters of credit and performance/surety bonds	12	12	—	—	—
Total	$19	$19	$—	$—	$—

* We provide a guarantee on behalf of our affiliate, SouthStar. We guarantee 70% of SouthStar's obligations to Southern Natural under certain agreements between the parties up to a maximum of $7 million if SouthStar fails to make payment to Southern Natural. We have certain guarantees that are recorded on our consolidated balance sheet that would not cause any additional impact on our financial statements beyond what was already recorded.

CASH FLOW FROM OPERATING ACTIVITIES

Our statement of cash flows is prepared using the indirect method. Under this method, net income is reconciled to cash flows from operating activities by adjusting net income for those items that impact net income but do not result in actual cash receipts or payments during the period. These reconciling items include depreciation, undistributed earnings from equity investments, changes in deferred income taxes, gains or losses on the sale of assets and changes in the balance sheet for working capital from the beginning to the end of the period.

We generate a large portion of our annual net income and subsequent increases in our accounts receivable in the first and fourth quarters due to significant volumes of natural gas delivered by distribution operations and SouthStar to our customers during the peak heating season. In addition, our natural gas inventories, which usually peak on November 1, are largely drawn down in the heating season and provide a source of cash as this asset is used to satisfy winter sales demand.

During this period, our accounts payable increases to reflect payments due to providers of the natural gas commodity and pipeline capacity. The value of the natural gas commodity can vary significantly from one period to the next as a result of the volatility in the price of natural gas. Our natural gas costs and deferred purchased natural gas costs due from or to our customers represent the difference between natural gas costs that have been paid to suppliers in the past and what has been collected from customers. These natural gas costs can cause significant variations in cash flows from period to period.

Our operating cash flow of $287 million for the year ended December 31, 2004 included SouthStar's operating cash flow of approximately $79 million as a result of our consolidation of SouthStar effective January 1, 2004. In 2003 and 2002, our operating cash flow only included amounts for cash distributions from SouthStar, consistent with the equity method of accounting. Excluding SouthStar, our cash flow from operations for the year ended December 31, 2004 was $208 million, an increase of $86 million from 2003. Year-to-year changes in our operating cash flow, excluding SouthStar, were primarily the result of increased earnings of $25 million and decreased spending for injection and purchase of natural gas inventories of $63 million.

Our cash flow from operations in 2003 was $122 million, a decrease of $164 million from 2002. This decrease was primarily the result of increased spending for injection of natural gas inventories of approximately 11 Bcf. The weighted average cost of this inventory increased approximately 30% compared to 2002. In addition, we made approximately $22 million in pension contributions in 2003 as a result of our continued efforts to fully fund our pension liability. This was offset by increased net income of $25 million and cash distributions received from SouthStar of $40 million.

CASH FLOW FROM INVESTING ACTIVITIES

Our cash used in investing activities in 2004 consisted primarily of property, plant and equipment (PP&E) expenditures and our acquisition of NUI for $116 million and Jefferson Island for $90 million. For more information on our acquisitions of NUI and Jefferson Island, see Note 2. In 2003, our investing activities included our cash payment of $20 million for the purchase of Dynegy's 20% interest in SouthStar. In 2002, we received $27 million in cash from SouthStar and US Propane. The following table provides additional information on our actual and estimated PP&E expenditures:

In millions	2005[1]	2004	2003	2002	2004 vs. 2003	2003 vs. 2002
Construction of distribution facilities	$ 87	**$ 64**	$ 60	$ 62	$ 4	$ (2)
Pipeline replacement program	85	**95**	45	48	50	(3)
Pivotal Propane plant	2	**29**	—	—	29	—
Telecommunications	5	**5**	8	28	(3)	(20)
Other	97	**71**	45	49	26	(4)
Total PP&E expenditures	$276	**$264**	$158	$187	$106	$(29)

[1] Estimated.

The increase of $106 million or 67% in PP&E expenditures for 2004 compared to 2003 was primarily due to increased PRP expenditures of $50 million and our construction of the Virginia propane plant by Pivotal Propane of $29 million. In addition, the increase was due to $9 million of expenditures for the construction of the Macon peaking pipeline, $7 million for the ETRM at Sequent, $3 million at Pivotal Jefferson Island and $3 million at SouthStar.

The decrease of $29 million or 15% in PP&E expenditures for 2003 compared to 2002 was primarily due to lower telecommunications expenditures of $20 million as a result of the completion of the metro Atlanta fiber network in 2002, a decrease in PRP expenditures of $3 million, and a decrease in construction of distribution facilities of $2 million associated with distribution operations.

For 2005, we estimate that our total PP&E expenditures will increase as a result of expenditures for the construction of distribution facilities of $23 million and acquisition and enhancement of the Southern Natural interstate pipeline for $38 million. Our expected increase in the construction of distribution facilities is primarily due to increased expenditures for renewals and the acquired NUI utilities.

Our PRP costs are expected to remain at current levels of spending, through the expected end of the program in 2008, primarily as a result of the replacement of larger-diameter pipe than in prior years, the majority of which is located in more densely populated areas. The PRP recoveries are recorded as revenues and are based on a formula that allows us to recover operation and maintenance costs in excess of those included in Atlanta Gas Light's base rates, depreciation expense and an allowed rate of return on capital expenditures. In the near term, the primary financial impact to us from the PRP is reduced cash flow from operating and investing activities, as the timing related to cost recovery does not match the timing of when costs are incurred. As discussed earlier, Atlanta Gas Light's current rate case includes testimony on whether the PRP should be included in its base rates or whether the rider currently used for recovery of PRP expenses should be otherwise modified or discontinued.

CASH FLOW FROM FINANCING ACTIVITIES

Our financing activities are primarily composed of borrowings and payments of short-term debt, payments of Medium-Term notes, borrowings of senior notes, distributions to minority interests, cash dividends on our common stock and the issuance of common stock. Our capitalization and financing strategy is intended to ensure that we are properly capitalized with the appropriate mix of equity and debt securities. This strategy includes active management by us of the percentage of total debt relative to our total capitalization, as well as the term and interest rate profile of our debt securities.

We also work to maintain or improve our credit ratings on our senior notes to effectively manage our existing financing costs and enhance our ability to raise additional capital on favorable terms. Factors we consider important in assessing our credit ratings include: our balance sheet leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that would require us to issue equity based on credit ratings or other trigger events. As of February 2005, our senior unsecured debt ratings are BBB+ from Standard & Poor's Ratings Services (S&P), Baa1 from Moody's Investors Service (Moody's) and A- from Fitch Ratings (Fitch).

During 2004, no fundamental adverse shift occurred in our ratings profile; however, upon the announcement of our proposed acquisition of NUI, S&P placed our credit ratings on CreditWatch with negative implications, Moody's affirmed our ratings but changed its rating outlook to negative from stable, and Fitch placed our credit ratings on Rating Watch Negative. Since the closing of the acquisition, S&P removed us from CreditWatch and changed our outlook to negative; Fitch took us off Rating Watch Negative and affirmed our ratings with a stable outlook; and Moody's affirmed our ratings and kept the negative outlook. S&P and Moody's have indicated that the negative outlook is the result of the execution risks in integrating the NUI acquisition.

Our credit ratings may be subject to revision or withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating. We cannot ensure that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. If the rating agencies downgrade our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources would decrease.

Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include maintaining covenants with respect to maximum leverage ratio, minimum net worth, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. Our Credit Facility's financial covenants and our PUHCA financing authority require us to maintain a ratio of total debt-to-total capitalization of no greater than 70%; however, our goal is to maintain this ratio at levels between 50% and 60% of debt-to-total-capitalization. We are currently in compliance with all existing debt provisions and covenants.

We believe that accomplishing these capitalization objectives and maintaining sufficient cash flow are necessary to maintain our investment-grade credit ratings and to allow us access to capital at reasonable costs. The components of our capital structure, as of the dates indicated, are summarized in the following table:

Dollars in millions	Dec 31, 2004		Dec 31, 2003	
Short-term debt	$ 334	10%	$ 383	16%
Long-term debt[1]	1,623	48	956	42
Total debt	1,957	58	1,339	58
Minority interest	36	1	—	—
Common shareholders' equity	1,385	41	945	42
Total capitalization	$3,378	100%	$2,285	100%

[1] Net of interest rate swaps.

Short-term Debt

Our short-term debt is composed of borrowings under our commercial paper program, Sequent's line of credit and SouthStar's line of credit. Our short-term debt financing generally increases between June and December because our payments for natural gas and pipeline capacity are generally made to suppliers prior to the collection of accounts receivable from our customers. In addition, we typically reduce short-term debt balances in the spring because a significant portion of our current assets are converted into cash at the end of the winter heating season.

In 2004, our $480 million of net short-term debt payments included the repayment of $500 million outstanding under NUI's credit facilities. Upon the repayment of the outstanding amounts, we terminated NUI's credit facilities.

Our commercial paper program is supported by our Credit Facility, which was amended on September 30, 2004. Under the terms of the amendment, the term of the Credit Facility was extended from May 26, 2007 to September 30, 2009. The aggregate principal amount available under the amended Credit Facility was increased from $500 million to $750 million, and our option to increase the aggregate cumulative principal amount available for borrowing on not more than one occasion during each calendar year was increased from $200 million to $250 million. As of December 31, 2004 and 2003, we had no outstanding borrowings under the Credit Facility. However, the availability of borrowings and unused availability under our Credit Facility is limited and subject to conditions specified within the Credit Facility, which we currently meet. These conditions include

- compliance with certain financial covenants
- the continued accuracy of representations and warranties contained in the agreement

Sequent uses its $25 million unsecured line of credit solely for the posting of margin deposits for NYMEX transactions, and it is unconditionally guaranteed by us. This line of credit expires on July 1, 2005 and bears interest at the federal funds effective rate plus 0.5%. At December 31, 2004, the line of credit had an outstanding balance of $18 million.

SouthStar's $75 million line of credit provides the additional working capital needed to meet seasonal demands and is not guaranteed by us. The line of credit is secured by various percentages of its accounts receivable, unbilled revenue and inventory. The line of credit expires in April 2007 and bears interest at the prime rate and/or LIBOR plus a margin based on certain financial measures. At December 31, 2004, there were no amounts outstanding under this facility; the interest rate would have been 5.25% based on the prime rate.

Long-term Debt

In 2004, AGL Capital issued $250 million of 6% senior notes due October 2034 and $200 million of 4.95% senior notes due January 2015. We fully and unconditionally guarantee the senior notes. The proceeds from the issuance were used to refinance a portion of our outstanding short-term debt under our commercial paper program. During 2004, we also made $82 million in Medium-Term note payments using proceeds from the borrowings under our commercial paper program. Additionally, NUI Utilities, Inc., a wholly owned subsidiary of NUI had outstanding at closing $199 million of indebtedness pursuant to Gas Facility Revenue Bonds and $10 million in capital leases, of which $2 million is reflected as current. For more information on our long-term debt including the debt assumed from the NUI acquisition, see Note 8.

In 2003, we issued $225 million of 4.45% senior notes due July 2013 and used the net proceeds to repay approximately $204 million of our Medium-Term notes and approximately $21 million of short-term debt. In 2002, we made $93 million in scheduled Medium-Term note payments using a combination of cash from operations and proceeds from our commercial paper program.

Interest Rate Swaps

To maintain an effective capital structure, it is our policy to borrow funds using a mix of fixed-rate debt and variable-rate debt. We have entered into interest rate swap agreements for the purpose of hedging the interest rate risk associated with our fixed-rate and variable-rate debt obligations. At December 31, 2004, including the effects of $175 million of interest rate swaps, 72% of our total short-term and long-term debt was fixed.

Minority Interest

As a result of our consolidation of SouthStar's accounts effective January 1, 2004, we recorded Piedmont's portion of SouthStar's contributed capital as a minority interest on our consolidated balance sheet and included it as a component of our total capitalization. We also recorded a cash distribution of $14 million for SouthStar's dividend distribution to Piedmont in our consolidated statement of cash flows as a financing activity.

Common Stock

In November 2004, we completed our public offering of 11.04 million shares of common stock, generating net proceeds of approximately $332 million. We used the proceeds to purchase the outstanding capital stock of NUI and to repay short-term debt incurred to fund our purchase of Jefferson Island.

In February 2003, we completed our public offering of 6.4 million shares of common stock. The offering generated net proceeds of approximately $137 million, which we used to repay outstanding short-term debt and for general corporate purposes.

Dividends on Common Stock

In February 2005, we announced a 7% increase in our common stock dividend, raising the quarterly dividend from $0.29 per share to $0.31 per share, which indicates an annual dividend of $1.24 per share. The new quarterly dividend will be paid March 1, 2005, to shareholders of record as of the close of business February 18, 2005. In April 2004, we announced a 4% increase in our common stock dividend, raising the quarterly dividend from $0.28 per share to $0.29 per share, which indicated an annual dividend of $1.16 per share. In April 2003, our common stock dividend was increased by 4% from $0.27 per share to $0.28 per share, which indicated an annual dividend of $1.12 per share. For information on the restrictions of our ability to pay dividends on common stock, see Note 9.

Shelf Registration

In October 2004, we filed a new shelf registration statement with the SEC for authority to increase our aggregate capacity to $1.5 billion of various capital securities. The shelf registration statement was declared effective in November 2004. We currently have remaining capacity under that registration statement of approximately $957 million. We may seek additional financing through debt or equity offerings in the private or public markets at any time.

CRITICAL ACCOUNTING POLICIES

The preparation of our financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. We evaluate our estimates on an ongoing basis, and our actual results may differ from these estimates. Each of the following critical accounting policies involves complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements.

REGULATORY ACCOUNTING

We account for transactions within our distribution operations segment according to the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). Applying this accounting policy allows us to defer expenses and income in the consolidated balance sheets as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the ratesetting process in a period different from the period in which they would have been reflected in the statements of consolidated income of an unregulated company. We then recognize these deferred regulatory assets and liabilities in our statements of consolidated income in the period in which we reflect the same amounts in rates.

If any portion of distribution operations ceased to continue to meet the criteria for application of regulatory accounting treatment for all or part of its operations, we would eliminate the regulatory assets and liabilities related to those portions ceasing to meet such criteria from our consolidated balance sheets and include them in our statements of consolidated income for the period in which the discontinuance of regulatory accounting treatment occurred.

PIPELINE REPLACEMENT PROGRAM (PRP)

Atlanta Gas Light was ordered by the Georgia Commission to undertake a PRP, which will replace all bare steel and cast iron pipe in its system in the state of Georgia within a 10-year period beginning October 1, 1998. Atlanta Gas Light initially identified, and provided notice to the Georgia Commission in accordance with this order, 2,312 miles of bare steel and cast iron pipe to be replaced. Atlanta Gas Light has subsequently identified an additional 188 miles of pipe subject to replacement under this program. If Atlanta Gas Light does not perform in accordance with this order, it can be assessed certain nonperformance penalties. However, to date, Atlanta Gas Light is in full compliance. The order also provides for recovery of all prudent costs incurred in the performance of the program, which Atlanta Gas Light has recorded as a regulatory asset. The regulatory asset has two components:

- the costs incurred to date that have not yet been recovered through rate riders
- the future expected costs to be recovered through rate riders

The determination of future expected costs involves judgment. Factors that must be considered in estimating the future expected costs are projected capital expenditure spending and remaining footage of infrastructure to be replaced for the remaining years of the program. Atlanta Gas Light recorded a long-term liability of $242 million as of December 31, 2004 and $323 million as of December 31, 2003, which represented engineering estimates for remaining capital expenditure costs in the PRP. As of December 31, 2004, Atlanta Gas Light had recorded a current liability of $85 million, representing expected PRP expenditures for the next 12 months. We report these estimates on an undiscounted basis. If the recorded liability for PRP had been higher or lower by $10 million, Atlanta Gas Light's expected recovery would have changed by approximately $1 million.

The PRP is also an issue in the current Atlanta Gas Light rate proceeding. It is possible the Georgia Commission may alter the recovery method for the costs we incur or may disallow cost recovery while maintaining the requirement to replace the bare steel and cast iron pipe. Changes to the recovery of PRP costs could result in an impairment of our regulatory asset of $361 million at December 31, 2004, if costs are disallowed or if it is no longer probable that accrued costs would be recoverable from ratepayers in the future.

ENVIRONMENTAL REMEDIATION LIABILITIES

Atlanta Gas Light historically reported estimates of future remediation costs based on probabilistic models of potential costs. We report these estimates on an undiscounted basis. As we continue to conduct the actual remediation and enter cleanup contracts, Atlanta Gas Light is increasingly able to provide conventional engineering estimates of the likely costs of many elements of its remediation program. These estimates contain various engineering uncertainties, and Atlanta Gas Light continuously attempts to refine and update these engineering estimates. In addition, Atlanta Gas Light continues to review technologies available for cleanup of its two largest sites, Savannah and Augusta, Georgia, which, if proven, could have the effect of further reducing its total future expenditures.

Our latest available estimate as of September 30, 2004 for those elements of the remediation program with in-place contracts or engineering cost estimates is $36 million. This is a reduction of $30 million from the estimate as of September 30, 2003 of projected engineering and in-place contracts, resulting from $50 million of program expenditures during the 12 months ended September 30, 2004. During this same 12-month period, Atlanta Gas Light realized increases in its future cost estimates totaling $20 million related to an increase in the contract value at Augusta, Georgia for treatment of two areas and additional deep excavation of contaminants; the addition of harbor sediment removal at St. Augustine; an increase at Savannah for the phase 2 excavation and a partially offsetting decrease in engineering and oversight costs; and an increase in program management costs due to legal matters, environmental regulatory activities and oversight costs for the extension of work at Savannah and Augusta. For elements of the remediation program where Atlanta Gas Light still cannot perform engineering cost estimates, considerable variability remains in available estimates. The estimated remaining cost of future actions at these sites is $14 million.

Atlanta Gas Light estimates certain other costs paid directly by it related to administering the remediation program and remediation of sites currently in the investigation phase. Through January 2006, Atlanta Gas Light estimates the administration costs to be $2 million. Beyond January 2006, these costs are not estimable. For those sites currently in the investigation phase our estimate is $9 million, which is based on preliminary data received during 2004 with respect to the existence of contamination of those sites. Our range of estimates for these sites is from $4 million to $15 million. We have accrued the midpoint of our range, or $9 million, as this is our best estimate at this phase of the remediation process.

Atlanta Gas Light's environmental remediation liability is included in its corresponding regulatory asset. As of December 31, 2004, the regulatory asset was $166 million, which is a combination of the accrued remediation liability and unrecovered cash expenditures. Atlanta Gas Light's estimate does not include other potential expenses, such as unasserted property damage, personal injury or natural resource damage claims, unbudgeted legal expenses, or other costs for which it may be held liable but with respect to which the amount cannot be reasonably forecast. Atlanta Gas Light's estimate also does not include any potential cost savings from the new cleanup technologies referenced above.

In New Jersey, Elizabethtown Gas is currently conducting remediation activities with oversight from the New Jersey Department of Environmental Protection. Although the actual total cost of future environmental investigation and remediation efforts cannot be estimated with precision, the range of reasonably probable costs is from $30 million to $116 million. As of December 31, 2004, no value within this range is better than any other value, so we recorded a liability of $30 million.

Elizabethtown Gas' prudently incurred remediation costs for the New Jersey properties have been authorized by the NJBPU to be recoverable in rates through its Remediation Adjustment Clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $34 million, inclusive of interest, as of December 31, 2004, reflecting the future recovery of both incurred costs and future remediation liabilities in the state of New Jersey. Elizabethtown Gas has also been successful in recovering a portion of remediation costs incurred in New Jersey from its insurance carriers and continues to pursue additional recovery. As of December 31, 2004, the variation between the amounts of the environmental remediation cost liability recorded on the consolidated balance sheet and the associated regulatory asset is due to expenditures for environmental investigation and remediation exceeding recoveries from ratepayers and insurance carriers.

We also own several former NUI remediation sites located outside of New Jersey. One site, in Elizabeth City, North Carolina, is subject to an order by the North Carolina Department of Energy and Natural Resources. We do not have precise estimates for the cost of investigating and remediating this site, although preliminary estimates for these costs range from $4 million to $16 million. As of December 31, 2004, we have recorded a liability of $4 million related to this site. There is another site in North Carolina where investigation and remediation is probable, although no regulatory order exists and we do not believe costs associated with this site can be reasonably estimated. In addition, there are as many as six other sites with which NUI had some association, although no basis for liability has been asserted. We do not believe that costs to investigate and remediate these sites, if any, can be reasonably estimated at this time.

With respect to these costs, we currently pursue or intend to pursue recovery from ratepayers, former owners and operators and insurance carriers. Although we have been successful in recovering a portion of these remediation costs from our insurance carriers, we are not able to express a belief as to the success of additional recovery efforts. We are working with the regulatory agencies to prudently manage our remediation costs so as to mitigate the impact of such costs on both ratepayers and shareholders.

REVENUE RECOGNITION

Rate structures for Elizabethtown Gas, Virginia Natural Gas, Florida Gas and Chattanooga Gas include volumetric rate designs that allow recovery of costs through gas usage. These utilities recognize revenues from sales of natural gas and transportation services in the same period in which they deliver the related volumes to customers. These utilities also bill and recognize sales revenues from residential and certain commercial and industrial customers on the basis of scheduled meter readings. In addition, they record revenues for estimated deliveries of gas, not yet billed to these customers, from the meter reading date to the end of the accounting period. We include these revenues in our consolidated balance sheets as unbilled revenue. Furthermore, included in the rates charged by Elizabethtown Gas, Virginia Natural Gas and Chattanooga Gas is a WNA factor, which offsets the impact of unusually cold or warm weather on operating margins.

PURCHASE PRICE ALLOCATION

During 2004, we completed two significant acquisitions, Jefferson Island and NUI. We purchased Jefferson Island for an adjusted price of $90 million, which included approximately $9 million of working gas inventory. We purchased NUI for $225 million in cash plus the assumption of NUI's outstanding net debt. At closing, NUI had $709 million in debt and approximately $109 million of cash on its balance sheet, bringing the net value of the transaction to approximately $825 million.

In accordance with SFAS No. 141, "Business Combinations" (SFAS 141), the purchase price of Jefferson Island and NUI should be allocated to the various assets and liabilities acquired at their estimated fair value. Estimating fair values can be complex and can require significant applications of judgment. It most commonly affects nonregulated property, plant and equipment, nonregulated assets and liabilities, and intangible assets, including those with indefinite lives. Our evaluation of NUI's identifiable assets acquired and liabilities assumed is a preliminary valuation based on currently available information and is subject to final adjustments. The valuations are considered preliminary since they are based on limited information available to management and independent appraisers. Generally, we have, if necessary, up to one year from the acquisition date to finalize the purchase price allocation. Any changes in estimates used in the allocation of the purchase price that are made after the one-year look-back period would be recognized in earnings during the period in which the change in estimate is made.

We expect to record goodwill associated with the acquisitions of Jefferson Island and NUI that will be required to be tested for impairment at least annually in accordance with the requirements of SFAS 142. The goodwill associated with the acquisition of NUI is expected to be allocated to our distribution operations segment. Based on our annual assessment at December 31, 2004, no impairment of goodwill is indicated, and our calculation indicates that the estimated fair value of this segment exceeds the carrying value, including goodwill, by a significant amount. For more information on our methodology used to test goodwill for impairment, see Note 1.

DERIVATIVES AND HEDGING ACTIVITIES

SFAS 133, as updated by SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149), established accounting and reporting standards which require that every derivative financial instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. However, if the derivative transaction qualifies for and is designated as a normal purchase and sale, it is exempted from the fair value accounting treatment of SFAS 133, as updated by SFAS 149, and is accounted for using traditional accrual accounting.

SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, SFAS 133 allows a derivative's gains and losses to offset related results on the hedged item in the income statement in the case of a fair value hedge, or to record the gains and losses in other comprehensive income until maturity in the case of a cash flow hedge. Additionally, SFAS 133 requires that a company formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment. Two areas where SFAS 133 applies are interest rate swaps and gas commodity contracts at both Sequent and SouthStar. Our derivative and hedging activities are described in further detail in Note 4.

Interest Rate Swaps

We designate our interest rate swaps as fair value hedges as defined by SFAS 133, which allows us to designate derivatives that hedge exposure to changes in the fair value of a recognized asset or liability. We record the gain or loss on fair value hedges in earnings in the period of change, together with the offsetting loss or gain on the hedged item attributable to the risk being hedged. The effect of this accounting is to reflect in earnings only that portion of the hedge that is not effective in achieving offsetting changes in fair value.

Commodity-related Derivative Instruments

We are exposed to risks associated with changes in the market price of natural gas. Elizabethtown Gas utilizes certain derivatives for non-trading purposes to hedge the impact of market fluctuations on assets, liabilities and other contractual commitments. Pursuant to SFAS 133, such derivative products are marked-to-market each reporting period. Pursuant to regulatory requirements, realized gains and losses related to such derivatives are reflected in purchased gas costs and included in billings to customers. Unrealized gains and losses are reflected as a regulatory asset (loss) or liability (gain), as appropriate, on the consolidated balance sheet. Through Sequent and SouthStar, we use derivative instruments to reduce our exposure to the risk of changes in the prices of natural gas. Sequent recognizes the change in value of derivative instruments as an unrealized gain or loss in revenues in the period when the market value of the portfolio changes. This is primarily due to newly originated transactions and the effect of price changes. Sequent recognizes cash inflows and outflows associated with the settlement of these risk management activities in operating cash flows and reports these settlements as receivables and payables separately from risk management activities in the balance sheet as energy marketing receivables and trade payables.

Under our risk management policy, we attempt to mitigate substantially all our commodity price risk associated with Sequent's gas storage portfolio and lock in the economic margin at the time we enter into gas purchase transactions for our stored gas. We purchase gas for storage when the current market price we pay for gas plus the cost to store the gas is less than the market price we could receive in the future by selling NYMEX futures contracts or other over-the-counter derivatives in the forward months, resulting in a positive net profit margin. We use contracts to sell gas at that future price to substantially lock in the profit margin we will ultimately realize when the stored gas is actually sold. These contracts meet the definition of a derivative under SFAS 133.

The purchase, storage and sale of natural gas are accounted for differently from the derivatives we use to mitigate the commodity price risk associated with our storage portfolio. The difference in accounting can result in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated. We do not currently use hedge accounting under SFAS 133 to account for this activity.

Gas that we purchase and inject into storage is accounted for on an accrual basis, at the lower of average cost or market, as inventory in our consolidated balance sheets and is no longer marked to market following our implementation of the accounting guidance in EITF 02-03. Under current accounting guidance, we would recognize a loss in any period when the market price for gas is lower than the carrying amount of our purchased gas inventory. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenues and cost of gas sold in our statement of consolidated income in the period we sell gas and it is delivered out of the storage facility.

The derivatives we use to mitigate commodity price risk and substantially lock in the margin upon the sale of stored gas are accounted for at fair value and marked to market each period, with changes in fair value recognized as unrealized gains or losses in the period of change. This difference in accounting, the accrual basis for our gas storage inventory versus mark-to-market accounting for the derivatives used to mitigate commodity price risk, can result in volatility in our reported net income. Based on Sequent's storage positions at December 31, 2004, a $0.10 forward NYMEX change would result in a $0.3 million impact to Sequent's EBIT.

Over time, gains or losses on the sale of gas storage inventory will be offset by losses or gains on the derivatives, resulting in realization of the economic profit margin we expected when we entered into the transactions. This accounting difference causes Sequent's earnings on its gas storage positions to be affected by natural gas price changes, even though the economic profits remain essentially unchanged. Sequent manages underground storage for our utilities and holds certain capacity rights on its own behalf. The underground storage is of two types:

- reservoir storage, where supplies are generally injected and withdrawn on a seasonal basis
- salt dome high-deliverability storage, where supplies may be periodically injected and withdrawn on relatively short notice

SouthStar also uses derivative instruments to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to minimize this risk using the most effective methods to reduce or eliminate the impacts of these exposures. A significant portion of SouthStar's derivative transactions are designated as cash flow hedges under SFAS 133. Derivative gains or losses arising from cash flow hedges are recorded in other comprehensive income (OCI) and are reclassified into earnings in the same period as the settlement of the underlying hedged item. Any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not perfectly offset the losses or gains on the hedged item, is recorded into earnings in the period in which it occurs.

SouthStar currently has minimal hedge ineffectiveness. SouthStar's remaining derivative instruments do not meet the hedge criteria under SFAS 133. Therefore, changes in their fair value are recorded in earnings in the period of change.

Weather Derivative Contracts

SouthStar enters into weather derivative contracts, from time to time, for hedging purposes in order to preserve margins in the event of warmer-than-normal weather in the winter months. SouthStar accounts for these contracts using the intrinsic value method under the guidelines of EITF 99-02, "Accounting for Weather Derivatives." There were no weather derivative contracts outstanding as of December 31, 2004 and 2003.

ACCOUNTING FOR CONTINGENCIES

Our accounting policies for contingencies cover a variety of business activities, including contingencies for potentially uncollectible receivables, rate matters, and legal and environmental exposures. We accrue for these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated in accordance with SFAS No. 5, "Accounting for Contingencies" (SFAS 5). We base our estimates for these liabilities on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Actual results may differ from estimates, and estimates can be, and often are, revised either negatively or positively, depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

For the majority of our receivables, we establish an allowance for doubtful accounts based on our collections experience. Some of the more important factors that we use in the preparation of our allowance amounts are the customer status, the customer's aging balance, and historical collection experience and trends. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances that could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices and general economic conditions.

ACCOUNTING FOR PENSION BENEFITS

We have a defined benefit pension plan for the benefit of substantially all full-time employees and qualified retirees. We use several statistical and other factors that attempt to anticipate future events and to calculate the expense and liability related to the plan. These factors include our assumptions about the discount rate, expected return on plan assets and rate of future compensation increases. In addition, our actuarial consultants use subjective factors such as withdrawal and mortality rates to estimate the projected benefit obligation. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, or longer or shorter life spans of participants. These differences may result in a significant impact on the amount of pension expense recorded in future periods.

At December 31, 2004, we increased our minimum pension liability by approximately $18 million, resulting in an aftertax loss to OCI of $11 million. At December 31, 2003, we reduced our minimum pension liability by approximately $14 million, which resulted in an aftertax gain to OCI of $8 million. These adjustments reflect our funding contributions to the plan and updated valuations for the projected benefit obligation and plan assets. To the extent that our future expenses and contributions increase as a result of the additional minimum pension liability, we believe that such increases are recoverable in whole or in part under future rate proceedings or mechanisms.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded accumulated benefit obligation (ABO), as the primary factors that drive the value of our unfunded ABO are the assumed discount rate and the actual return on plan assets. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes the differences between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year moving weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year moving weighted average methodology, which affects the expected return on plan assets component of pension expense.

A one-percentage-point increase in the assumed discount rate would decrease the AGL Resources Inc. Retirement Plan's ABO by approximately $37 million and would decrease annual pension expense by approximately $4 million. A one-percentage-point decrease in the assumed discount rate would increase the AGL Resources Inc. Retirement Plan's ABO by approximately $46 million and would increase annual pension expense by approximately $4 million. Additionally, a one-percentage-point increase or decrease in the expected return on assets would decrease or increase the AGL Resources Inc. Retirement Plan's pension expense by approximately $3 million.

Additionally, we have recorded a $36 million liability for the amount of NUI's projected benefit obligation in excess of the fair value of pension plan assets at the date of our acquisition of NUI. The acquisition will impact our pension plan expenses and liabilities. A one-percentage-point increase in the discount rate would decrease the NUI Corporation Retirement Plan's ABO by approximately $12 million and would decrease the annual benefit cost by approximately $0.1 million. A one-percentage-point decrease in the discount rate would increase the NUI Corporation Retirement Plan's ABO by approximately $13 million, and increase our annual expense by approximately $0.1 million. In addition, a one-percentage-point increase or decrease in the NUI Corporation Retirement Plan's expected return on assets would decrease or increase our pension expenses by approximately $0.1 million.

As of December 31, 2004, the market value of the pension assets was $390 million compared to a market value of $259 million as of December 31, 2003. The net increase of $131 million resulted from

- contributions of $13 million in April 2004
- contributions of $1 million in 2004 to our supplemental retirement plan
- an actual return on plan assets of $26 million less benefits paid of $19 million
- the acquisition of NUI assets of $111 million

Our $13 million in contributions to the pension plan in 2004 reduced annual pension expense by approximately $1 million in 2004. The actual return on plan assets compared to the expected return on plan assets will have an impact on our benefit obligation as of December 31, 2004, and our pension expense for 2005. We are unable to determine how this actual return on plan assets will affect future benefit obligation and pension expense, as actuarial assumptions and differences between actual and expected returns on plan assets are determined at the time we complete our actuarial evaluation as of December 31, 2004. Our actual returns may also be positively or negatively impacted as a result of future performance in the equity and bond markets.

ACCOUNTING DEVELOPMENTS

For information regarding accounting developments, see Note 3.

RISK FACTORS

The following are some of the factors that could affect our future performance or could cause actual results to differ materially from those expressed or implied in our forward-looking statements. We cannot predict every event and circumstance that may adversely affect our business, and therefore the risks and uncertainties described below may not be the only ones we face. Additional risks and uncertainties that we are unaware of, or that we currently deem immaterial, also may become important factors that cause serious damage to our business in the future.

RISKS RELATED TO THE NUI ACQUISITION

We may encounter difficulties integrating NUI into our business and may not fully attain or retain, or achieve within a reasonable time frame, expected strategic objectives, cost savings and other benefits of the acquisition.

We expect to realize strategic and other benefits as a result of our acquisition of NUI. Our ability to realize these benefits or successfully integrate NUI's businesses, however, is subject to certain risks and uncertainties, including:

- The costs of integrating NUI and upgrading and enhancing its operations may be higher than we expect and may require more resources, capital expenditures and management attention than anticipated.
- Employees important to NUI's operations may decide not to continue employment with us.
- We may be required to allocate some of the cost savings achieved through the integration of NUI to our existing regulated utilities, which could prevent us from retaining some of the benefits achieved if the allocated cost savings result in rate reductions in future rate proceedings.
- We may be unable to maintain and enhance our relationship with NUI's existing customers and regulators.
- We may be unable to anticipate or manage risks that are unique to NUI's business, including those related to its workforce, customer demographics, regulatory environment, information systems and diverse geography.
- We may be unable to appropriately and in a timely manner adapt to both existing and changing economic, regulatory and competitive conditions.

- The financial results of operations we acquired are subject to many of the same factors that have historically affected our financial condition and results of operations, including weather sensitivity; extensive federal, state and local regulation; increasing gas costs; competition and market risks; and national, regional and local economic conditions.

Our failure to manage these risks, or other risks related to the acquisition that are not presently known to us, could prevent us from realizing the expected benefits of the acquisition and also may have a material adverse effect on our results of operations and financial condition following the transaction.

NUI has certain liabilities and obligations related to its pre-acquisition activities that may result in unanticipated costs and expenses to us.
NUI has been, and continues to be, the subject of various lawsuits, regulatory audits, investigations and settlements related to certain of its and its affiliates' business practices prior to the date of the acquisition agreement. We will bear the costs of any liability, expense or obligation related to ongoing or new lawsuits, regulatory audits, investigations or claims related to these pre-acquisition activities. Additionally, management of these claims and liabilities may require a disproportionate amount of our management's time and attention. A failure to manage these risks could negatively affect our results of operations, our financial condition and our reputation in the industry, and may reduce the anticipated benefits of the acquisition.

NUI has material weaknesses in its internal controls that may force us to incur unanticipated costs to resolve after closing.
NUI's external and internal auditors performed audits during its fiscal 2003 and 2004 years that identified material weaknesses in NUI's internal controls. Additional internal control issues and deficiencies were identified in the focused audit of NUI and its affiliates that was conducted at the request of the NJBPU. We have initiated our efforts to assess the systems of internal control related to NUI's business in order to comply with the requirements of SOX 404. At this time, however, we believe these operations continue to have material deficiencies in their internal controls that we will be required to address and resolve. We cannot make any assurance that our systems of internal and disclosure controls and procedures will be able to detect or prevent all errors or fraud or ensure that all material information regarding weaknesses in controls will be made known to management in the near term. We may incur significant additional costs to resolve these internal control and disclosure issues.

RISKS RELATED TO OUR BUSINESS

Risks related to the regulation of our businesses could affect the rates we are able to charge, our costs and our profitability.
Our businesses are subject to regulation by federal, state and local regulatory authorities. In particular, our distribution businesses are regulated by the SEC under the PUHCA, the Georgia Commission, the Tennessee Authority, the NJPBU, the Florida Commission, the Virginia Commission and the Maryland Commission. These authorities regulate many aspects of our distribution operations, including construction and maintenance of facilities, operations, safety, rates that we can charge customers, rates of return, the authorized cost of capital, recovery of pipeline replacement and environmental remediation costs, carrying costs we charge Marketers for gas held in storage for their customer accounts and relationships with our affiliates. Our ability to obtain rate increases and rate supplements to maintain our current rates of return depends on regulatory discretion, and there can be no assurance that we will be able to obtain rate increases or rate supplements or continue receiving our currently authorized rates of return.

Deregulation in the natural gas industry is the separation of the provision and pricing of local distribution gas services into discrete components. Deregulation typically focuses on the separation of the gas distribution business from the gas sales business and is intended to cause the opening of the formerly regulated sales business to alternative unregulated suppliers of gas sales services.

In 1997, the Georgia legislature enacted the Natural Gas Competition and Deregulation Act. To date, Georgia is the only state in the nation that has fully deregulated gas distribution operations, which ultimately resulted in Atlanta Gas Light exiting the retail natural gas sales business while retaining its gas distribution operations. Gas marketers then assumed the retail gas sales responsibility at deregulated prices. The deregulation process required Atlanta Gas Light to completely reorganize its operations and personnel at significant expense. It is possible that the legislature could reverse the deregulation process and require or permit Atlanta Gas Light to provide retail gas sales service once again or require SouthStar to change the nature of how it provides natural gas to certain customers. In addition, the Georgia Commission has statutory authority on an emergency basis to order Atlanta Gas Light to temporarily provide the same retail gas service that it provided prior to deregulation. If any of these events were to occur, we would incur costs to reverse the restructuring process or potentially lose the earnings opportunity embedded within the current marketing framework. Furthermore, the Georgia Commission has authority to change the terms under which we charge Marketers for certain supply-related services, which could also affect our future earnings.

We have a concentration of credit risk in Georgia, which could expose a significant portion of our accounts receivable to collection risks.
We have a concentration of credit risk related to the provision of natural gas services to Georgia's Marketers. At September 30, 1998 (prior to deregulation), Atlanta Gas Light had approximately 1.4 million end-use customers in Georgia. In contrast, at December 31, 2004, Atlanta Gas Light had only 10 certificated and active Marketers in Georgia, four of which (based on customer count and including SouthStar) accounted for approximately 46% of our total operating margin for 2004. As a result, Atlanta Gas Light now depends on a concentrated number of customers for revenues. The failure of these Marketers to pay Atlanta Gas Light could adversely affect Atlanta Gas Light's business and results of operations and expose it to difficulties in collecting Atlanta Gas Light's accounts receivable. Additionally, SouthStar markets directly to end-use customers and has periodically experienced credit losses as a result of cold weather, variable prices and customers' inability to pay.

Our revenues, operating results and financial condition may fluctuate with the economy and its corresponding impact on our customers.
Our business is influenced by fluctuations in the economy. As a result, adverse changes in the economy can have negative effects on our revenues, operating results and financial condition. The level of economic and population growth in our regulated operations' service territories, particularly new housing starts, directly affects our potential for growing our revenues.

The cost of providing pension and postretirement health care benefits to eligible former employees is subject to changes in pension fund values and changing demographics, and may have a material adverse effect on our financial results.
We have a defined benefit pension plan for the benefit of substantially all full-time employees and qualified retirees. See "Critical Accounting Policies." The cost of providing these benefits to eligible current and former employees is subject to changes in the market value of our pension fund assets and changing demographics, including longer life expectancy of beneficiaries and an expected increase in the number of eligible former employees over the next five years.

We believe that sustained declines in equity markets and reductions in bond yields have had and may continue to have a material adverse effect on the value of our pension funds. In these circumstances, we may be required to recognize an increased pension expense or a charge to our statement of income to the extent that the pension fund values are less than the total anticipated liability under the plans.

We face increasing competition, and if we are unable to compete effectively, our revenues, operating results and financial condition will be adversely affected.
The natural gas business is highly competitive, and we are facing increasing competition from other companies that supply energy, including electric companies, oil and propane providers and, in some cases, energy marketing and trading companies. In particular, the success of our investment in SouthStar is affected by the competition SouthStar faces from other energy marketers providing retail gas services in the Southeast. Natural gas competes with other forms of energy. The primary competitive factor is price. Changes in the price or availability of natural gas relative to other forms of energy and the ability of end-users to convert to alternative fuels affect the demand for natural gas. In the case of industrial and agricultural customers, adverse economic conditions, including higher gas costs, could also cause these customers to bypass our systems in favor of special competitive contracts with lower per unit costs.

Our wholesale services segment competes with larger, full-service energy providers, which may limit our ability to grow our business.
Wholesale services competes with national and regional full-service energy providers, energy merchants, and producers and pipelines for sales based on our ability to aggregate competitively priced commodities with transportation and storage capacity. Some of our competitors are larger and better capitalized than we are and have more national and global exposure than we do. The consolidation of this industry and the pricing to gain market share may affect our margins. We expect this trend to continue in the near term, and the increasing competition for asset management deals could result in downward pressure on the volume of transactions and the related margins available in this portion of Sequent's business.

Our asset management arrangements between Sequent and the affiliated local distribution companies and between Sequent and its nonaffiliated customers may not be renewed or may be renewed at lower levels, which could have a significant impact on Sequent's business.
Sequent currently manages the storage and transportation assets of our affiliates Atlanta Gas Light, Virginia Natural Gas and Chattanooga Gas and shares profits it earns from the management of those assets with those customers and their customers. In addition, Sequent has asset management agreements with certain nonaffiliated customers.

On April 1, 2005, Sequent plans to commence asset management responsibilities for Elizabethtown Gas, Florida Gas and Elkton Gas. The contract terms are currently being negotiated. Sequent's results could be significantly impacted if these agreements are not renewed or are amended or renewed with less favorable terms.

Our profitability may decline if the counterparties to our transactions fail to perform in accordance with our agreements.

Wholesale services focuses on capturing the value from idle or under-utilized energy assets, typically by executing transactions that balance the needs of various markets and time horizons. Wholesale services is exposed to the risk that counterparties to our transactions will not perform their obligations. Should the counterparties to these arrangements fail to perform, we might be forced to enter into alternative hedging arrangements, honor the underlying commitment at then-current market prices or return a significant portion of the consideration received for gas under a long-term contract. In such events, we might incur additional losses to the extent of amounts, if any, already paid to or received from counterparties.

We have a concentration of credit risk at Sequent that could expose us to collection risks.

We often extend credit to our counterparties. Despite performing credit analysis prior to extending credit and seeking to effectuate netting agreements, we are exposed to the risk that we may not be able to collect amounts owed to us. If the counterparty to such a transaction fails to perform and any collateral we have secured is inadequate, we could experience material financial losses.

We have a concentration of credit risk at Sequent, which could expose a significant portion of our credit exposure to collection risks. Approximately 57% of Sequent's credit exposure is concentrated in 20 counterparties. Although most of this concentration is with counterparties that are either load-serving utilities or end-use customers and that have supplied some level of credit support, default by any of these counterparties in their obligations to pay amounts due Sequent could result in credit losses that would negatively impact our wholesale services segment.

We are exposed to market risk and may incur losses in wholesale services.

The commodity, storage and transportation portfolios at Sequent consist of contracts to buy and sell natural gas commodities, including contracts that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate, we could experience financial losses from our trading activities. Value at risk (VaR) is defined as the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability. Based on a 95% confidence interval and employing a 1-day and a 10-day holding period for all positions, Sequent's portfolio of positions as of December 31, 2004 had a 1-day holding period VaR of $0.1 million and a 10-day holding period VaR of $0.2 million.

Our accounting results may not be indicative of the risks we are taking or the economic results we expect due to changes in accounting for wholesale services.

Although Sequent enters into various contracts to hedge the value of our energy assets and operations, the timing of the recognition of profits or losses on the hedges does not always match up with the profits or losses on the item being hedged. This can result in volatility in reported earnings from one period to the next that does not exist from an economic standpoint over the full life of the hedge and the hedged item.

Our business is subject to environmental regulation in all jurisdictions in which we operate and our costs to comply are significant, and any changes in existing environmental regulation could negatively affect our results of operations and financial condition.

Our operations and properties are subject to extensive environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. Such environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances into the environment. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Our current costs to comply with these laws and regulations are significant to our results of operations and financial condition. Failure to comply with these laws and regulations and failure to obtain any required permits and licenses may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations.

In addition, claims against us under environmental laws and regulations could result in material costs and liabilities. Existing environmental regulations could also be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur. With the trend toward stricter standards, greater regulation, more extensive permit requirements and an increase in the number and types of assets operated by us subject to environmental regulation, our environmental expenditures could increase in the future, particularly if those costs are not fully recoverable from our customers. Additionally, the discovery of presently unknown environmental conditions could give rise to expenditures and liabilities, including fines or penalties, which could have a material adverse effect on our business, results of operations or financial condition.

We could incur additional material costs for the environmental condition of some of our assets, including former manufactured gas plants.

We are generally responsible for all on-site and certain off-site liabilities associated with the environmental condition of the natural gas assets that we have operated, acquired or developed, regardless of when the liabilities arose and whether they are or were known or unknown. In addition, in connection with certain acquisitions and sales of assets, we may obtain, or be required to provide, indemnification against certain environmental liabilities. Before natural gas was widely available in the Southeast, we manufactured gas from coal and other fuels. Those manufacturing operations were known as manufactured gas plants, or MGPs, which we ceased operating in the 1950s.

We have identified 10 sites in Georgia and 3 in Florida where we, or our predecessors, own or owned all or part of an MGP site. We are required to investigate possible environmental contamination at those MGP sites and, if necessary, clean up any contamination. To date, cleanup has been completed at these sites, and as of December 31, 2004, the remediation program was approximately 78% complete. As of December 31, 2004, projected costs associated with the MGP sites were $56 million. For elements of the MGP program where we still cannot perform engineering cost estimates, considerable variability remains in available future cost estimates.

In addition, NUI is associated with as many as 6 former sites in New Jersey and 10 former sites in other states. Material cleanups of these sites have not been completed nor are precise estimates available for future cleanup costs. For the New Jersey sites, cleanup cost estimates range from $30 million to $116 million. Costs have been estimated for only 1 of the 10 non–New Jersey sites, for which current estimates range from $4 million to $16 million.

The success of our telecommunications business strategy may be adversely affected by uncertain market conditions.

The current strategy of our telecommunications business is based on our ability to lease telecommunications conduit and dark fiber in the Atlanta, Georgia and Phoenix, Arizona metropolitan areas. The market for these services, like the telecommunications industry in general, is very competitive, rapidly changing and currently suffering from lack of market commitments. We cannot be certain that growth in demand for these services will occur as expected. If the market for these services fails to grow as anticipated or becomes saturated with competitors, including competitors using alternative technologies, our investment in the telecommunications business may be adversely affected.

Future acquisitions and expansions, if any, may affect our business by increasing the level of our indebtedness and contingent liabilities and creating integration difficulties.

From time to time, we may evaluate and acquire assets or businesses or enter into joint venture arrangements that we believe complement our existing businesses and related assets. As a result, the relative makeup of our business is subject to change. These acquisitions and joint ventures may require substantial capital or the incurrence of additional indebtedness. Further, acquired operations or joint ventures may not achieve levels of revenues, operating income or productivity comparable to those of our existing operations or may not otherwise perform as expected. Realization of the anticipated benefits of acquisitions or other transactions could take longer than expected. Acquisitions or joint ventures may also involve a number of risks, including

- our inability to integrate operations, systems and procedures
- the assumption of unknown risks and liabilities
- diversion of management's attention and resources
- difficulty retaining and training acquired key personnel

Our ability to successfully make strategic acquisitions and investments will depend on

- the extent to which acquisitions and investment opportunities become available
- our success in bidding for the opportunities that do become available
- regulatory approval, if required, of the acquisitions on favorable terms
- our access to capital and the terms upon which we obtain capital
- if we are unable to make strategic investments and acquisitions, we may be unable to grow

Our growth may be restricted by the capital-intensive nature of our business.

In order to maintain our historic growth, we must construct additions to our natural gas distribution system each year. The cost of this construction may be affected by the cost of obtaining government approvals, development project delays or changes in project costs. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost of a project. Our cash flows are not fully adequate to finance the cost of this construction. As a result, we must fund a portion of our cash needs through borrowings and the issuance of common stock. Our ability to finance the cost of constructing additions to our system depends on our ability to borrow funds or sell our common stock.

Changes in weather conditions may affect our earnings.
Weather conditions and other natural phenomena can have a large impact on our earnings. Severe weather conditions can impact our suppliers and the pipelines that deliver gas to our distribution system. Extended mild weather, either during the winter period or summer period, can have a significant impact on demand for and the cost of natural gas.

We have a WNA mechanism for Elizabethtown Gas, Chattanooga Gas and Virginia Natural Gas that partially offsets the impact that unusually cold or warm weather has on residential and commercial customer billings and margin. The WNA is most effective in a reasonable temperature range relative to normal weather using historical averages. The protection afforded by the WNA depends on continued regulatory approval. The loss of this continued regulatory approval could make us more susceptible to weather-related earnings fluctuations.

Inflation and increased gas costs could adversely impact our customer base and customer collections and increase our level of indebtedness.
Inflation has caused increases in certain operating expenses and has required us to replace assets at higher costs. We have a process in place to continually review the adequacy of our utility gas rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those gas rates. Historically, we have been able to budget and control operating expenses and investments within the amounts authorized to be collected in rates and intend to continue to do so. The ability to control expenses is an important factor that will influence future results.

Rapid increases in the price of purchased gas, which occurred in some prior years, cause us to experience a significant increase in short-term debt because we must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our utility collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher-than-normal accounts receivable. This situation also results in higher short-term debt levels and increased bad debt expense. Should the price of purchased gas increase significantly in the upcoming heating season, we would expect increases in our short-term debt, accounts receivable and bad debt expense during 2005.

Finally, higher costs of natural gas in recent years have already caused many of our utility customers to conserve in the use of our gas services and could lead to even more customers utilizing such conservation methods.

A decrease in the availability of adequate pipeline transportation capacity could reduce our revenues and profits.
Our gas supply depends on the availability of adequate pipeline transportation and storage capacity. We purchase a substantial portion of our gas supply from interstate sources. Interstate pipeline companies transport the gas to our system. A decrease in interstate pipeline capacity available to us or an increase in competition for interstate pipeline transportation and storage service could reduce our normal interstate supply of gas.

RISKS RELATED TO OUR CORPORATE AND FINANCIAL STRUCTURE

If we breach any of the material financial covenants under our various indentures, credit facilities or guarantees, our debt service obligations could be accelerated.
Our existing debt and the debt of certain of our subsidiaries contain a number of significant financial covenants. If we, or any of these subsidiaries breach any of the financial covenants under these agreements, our debt repayment obligations under them could be accelerated. In such event, we may not be able to refinance or repay all our indebtedness, which would result in a material adverse effect on our business, results of operations and financial condition.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part.
Our Credit Facility and the indenture under which Atlanta Gas Light's outstanding Medium-Term notes were issued contain cross-default provisions. Accordingly, should an event of default occur under some of our debt agreements, we face the prospect of being in default under other of our debt agreements, obliged in such instance to satisfy a large portion of our outstanding indebtedness and unable to satisfy all of our outstanding obligations simultaneously.

We depend on our ability to successfully access the capital markets. Any inability to access the capital or financial markets may limit our ability to execute our business plan or pursue improvements that we may rely on for future growth.
We rely on access to both short-term money markets (in the form of commercial paper) and long-term capital markets as a source of liquidity for capital and operating requirements not satisfied by the cash flow from our operations. If we are not able to access financial markets at competitive rates, our ability to implement our business plan and strategy will be affected. Certain market disruptions may increase our cost of borrowing or affect our ability to access one or more financial markets. Such market disruptions could result from

- adverse economic conditions
- adverse general capital market conditions
- poor performance and health of the utility industry in general
- bankruptcy or financial distress of unrelated energy companies or Marketers in Georgia
- decreases in the market price of and demand for natural gas
- adverse regulatory actions that affect our local gas distribution companies
- terrorist attacks on our facilities or our suppliers

Increases in our leverage could adversely affect our competitive position and financial condition.
An increase in our debt relative to our total capitalization could adversely affect us by

- increasing the cost of future debt financing
- limiting our ability to obtain additional financing, if we need it, for working capital, acquisitions, debt service requirements or other purposes
- making it more difficult for us to satisfy our existing financial obligations
- requiring us to dedicate a substantial portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future business opportunities or other purposes
- prohibiting the payment of dividends on our common stock or adversely impacting our ability to pay such dividends at the current rate
- increasing our vulnerability to adverse economic and industry conditions
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we compete

Changing rating agency requirements could negatively affect our growth and business strategy, and a downgrade in our credit rating could negatively affect our ability to access capital.
S&P, Moody's and Fitch have recently implemented new requirements for various ratings levels. In order to maintain our current credit ratings in light of these or future new requirements, we may need to take steps or change our business plans in ways that may affect our growth and earnings per share. S&P, Moody's and Fitch currently assign our senior unsecured debt a rating of BBB+, Baa1 and A, respectively. Our commercial paper currently is rated A-2, P-2 and F-2 by S&P, Moody's and Fitch, respectively. If the rating agencies downgrade our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources would likely decrease.

Additionally, if our credit rating by either S&P or Moody's falls to non–investment grade status, we will be required to provide additional support for certain customers of our wholesale business. As of December 31, 2004, if our credit rating had fallen below investment grade, we would have been required to provide collateral of approximately $20 million to continue conducting our wholesale services business with certain counterparties.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.
We use derivatives, including futures, forwards and swaps, to manage our commodity and financial market risks. We could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could adversely affect the value of the reported fair value of these contracts.

We depend on cash flow from our operations to pay dividends on our common stock.
We depend on dividends or other distributions of funds from our subsidiaries to pay dividends on our common stock. Payments of our dividends will depend on our subsidiaries' earnings and other business

considerations and may be subject to statutory or contractual obligations. Additionally, payment of dividends on our common stock is at the sole discretion of our Board of Directors.

We are vulnerable to interest rate risk with respect to our debt, which could lead to changes in interest expense.
We are subject to interest rate risk in connection with the issuance of fixed-rate and variable-rate debt. In order to maintain our desired mix of fixed-rate and variable-rate debt, we use interest rate swap agreements and exchange fixed-rate and variable-rate interest payment obligations over the life of the arrangements, without exchange of the underlying principal amounts. See "Quantitative and Qualitative Disclosures About Market Risk." We cannot assure you that we will be successful in structuring such swap agreements to effectively manage our risks. If we are unable to do so, our earnings may be reduced. In addition, higher interest rates, all other things equal, reduce the earnings that we derive from transactions where we capture the difference between authorized returns and short-term borrowings.

Our tax rate may be increased and/or tax laws affecting us can change that may have an adverse impact on our cash flows and profitability.
The rates of federal, state and local taxes applicable to the industries in which we operate, which often fluctuate, could be increased by the respective taxing authorities. In addition, the tax laws, rules and regulations that affect our business could change. Any such increase or change could adversely impact our cash flows and profitability.

RISKS RELATED TO OUR INDUSTRY

Transporting and storing natural gas involves numerous risks that may result in accidents and other operating risks and costs.
Our gas distribution activities involve a variety of inherent hazards and operating risks, such as leaks, accidents and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution and impairment of our operations, which in turn could lead to substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The location of pipelines and storage facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect our financial position and results of operations.

Natural disasters, terrorist activities and the potential for military and other actions could adversely affect our businesses.
Natural disasters may damage our assets. The threat of terrorism and the impact of retaliatory military and other action by the United States and its allies may lead to increased political, economic and financial market instability and volatility in the price of natural gas that could affect our operations. In addition, future acts of terrorism could be directed against companies operating in the United States, and companies in the energy industry may face a heightened risk of exposure to acts of terrorism. These developments have subjected our operations to increased risks. The insurance industry has also been disrupted by these events. As a result, the availability of insurance covering risks against which we and our competitors typically insure may be limited. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms.

Recent investigations and events involving the energy markets have resulted in an increased level of public and regulatory scrutiny in the energy industry and in the capital markets, resulting in increased regulation and new accounting standards.
As a result of the bankruptcy and adverse financial condition affecting several entities, particularly the bankruptcy filing by Enron, recently discovered accounting irregularities of various public companies and investigations by governmental authorities into energy trading activities, public companies, including particularly those in the energy industry, have been under an increased amount of public and regulatory scrutiny. Recently discovered practices and accounting irregularities have caused regulators and legislators to review current accounting practices, financial disclosures and relationships between companies and their independent auditors. New laws, such as the Sarbanes-Oxley Act of 2002, and regulations to address these concerns have been and continue to be adopted, and capital markets and rating agencies have increased their level of scrutiny. Costs related to increased scrutiny may have an adverse effect on our business, financial condition and access to capital markets. In addition, the FASB or the SEC could enact new accounting standards that could impact the way we are required to record revenues, assets and liabilities. These changes in accounting standards could lead to negative impacts on our reported earnings or increases in our liabilities.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to risks associated with commodity prices, interest rates and credit. Commodity price risk is defined as the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business, but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services.

Our Risk Management Committee (RMC) is responsible for the overall establishment of risk management policies and the monitoring of compliance with, and adherence to the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of senior executives who monitor commodity price risk positions, corporate exposures, credit exposures and overall results of our risk management activities, and is chaired by our chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions. Our risk management activities and related accounting treatments are described in further detail in Note 4.

COMMODITY PRICE RISK

Wholesale Services

This segment routinely utilizes various types of financial and other instruments to mitigate certain commodity price risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and over-the-counter energy contracts, such as forward contracts, futures contracts, option contracts and financial swap agreements. The following table includes the fair values and average values of our energy marketing and risk management assets and liabilities as of December 31, 2004 and 2003. We base the average values on monthly averages for the years ended December 31, 2004 and 2003.

In millions	Average 12-month Values		Value at:	
	2004	2003	**Dec 31, 2004**	Dec 31, 2003
Asset				
Natural gas contracts	**$28**	$14	**$36**	$13

In millions	Average 12-month Values		Value at:	
	2004	2003	**Dec 31, 2004**	Dec 31, 2003
Liability				
Natural gas contracts	**$21**	$14	**$19**	$18

We employ a systematic approach to the evaluation and management of the risks associated with our contracts related to wholesale marketing and risk management, including VaR. VaR is defined as the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability. We use a 1-day and a 10-day holding period and a 95% confidence interval to evaluate our VaR exposure. A 95% confidence interval means there is a 5% probability that the actual change in portfolio value will be greater than the calculated VaR value over the holding period. We calculate VaR based on the variance-covariance technique. This technique requires several assumptions for the basis of the calculation, such as price volatility, confidence interval and holding period. Our VaR may not be comparable to a similarly titled measure of another company because, although VaR is a common metric in the energy industry, there is no established industry standard for calculating VaR or for the assumptions underlying such calculations.

Our open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management, including the chief risk officer. Because we generally manage physical gas assets and economically protect our positions by hedging in the futures markets, our open exposure is generally minimal, permitting us to operate within relatively low VaR limits. We employ daily risk testing, using both VaR and stress testing, to evaluate the risks of our open positions.

Our management actively monitors open commodity positions and the resulting VaR. We continue to maintain a relatively matched book, where our total buy volume is close to sell volume, with minimal open commodity risk. Based on a 95% confidence interval and employing a 1-day and a 10-day holding period for all positions, our portfolio of positions for the years ended December 31, 2004 and 2003 had the following 1-day and 10-day holding period VaRs:

In millions	1-day	10-day
2004		
Period end	**$0.1**	**$0.2**
12-month average	**0.1**	**0.3**
High	**0.4**	**1.3**
Low[1]	**0.0**	**0.0**
2003		
Period end	$0.3	$1.0
12-month average	0.1	0.3
High	2.5	4.7
Low[1]	0.0	0.0

[1] $0.0 values represent amounts less than $0.1 million.

Energy Investments

SouthStar's use of derivatives is governed by a risk management policy created and monitored by its risk management committee which prohibits the use of derivatives for speculative purposes. This policy also establishes VaR limits of $0.5 million on a 1-day holding period and $0.7 million on a 10-day holding period. A 95% confidence interval is used to evaluate VaR exposure. The maximum VaR experienced during 2004 was less than $0.2 million for the 1-day holding period and $0.5 million for the 10-day holding period.

INTEREST RATE RISK

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. Our policy is to manage interest expense using a combination of fixed-rate and variable-rate debt. To facilitate the achievement of desired fixed- to variable-rate debt ratios, AGL Capital entered into interest rate swaps, whereby it agreed to exchange, at specified intervals, the difference between fixed and variable amounts calculated by reference to agreed-upon notional principal amounts. These swaps are designated to hedge the fair values of $100 million of the $300 million Senior Notes due 2011, and $75 million of the $150 million principal amount of notes payable to Trusts due in 2041. In March 2004, we adjusted our fixed- to variable-rate debt obligations and terminated an interest rate swap on $100 million of the $225 million principal amount of Senior Notes due 2013. More information about our interest rate swaps are shown in the following table:

Dollars in millions		Market Value of Interest Rate Swap Derivatives		Market Value as of:	
Notional Amount	Fixed-rate	Effective Variable Rate[1]	Maturity	**Dec 31, 2004**	Dec 31, 2003
$75	8.0%	3.6%	May 15, 2041	**$ 3**	$ 3
$100	7.1	5.2	January 14, 2011	**(2)**	(2)
$100	4.5	—	April 15, 2013[2]	**—**	(5)

[1] As of December 31, 2004.

[2] Terminated in March 2004.

CREDIT RISK

Distribution Operations

Atlanta Gas Light has a concentration of credit risk because it bills only 10 Marketers in Georgia for its services. The credit risk exposure to Marketers varies with the time of the year, with exposure at its lowest in the nonpeak summer months and highest in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of the natural gas commodity. These Marketers, in turn, bill end-use customers. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light. For 2004, the four largest Marketers based on customer count, one of which was SouthStar, accounted for approximately 46% of our operating margin and 61% of distribution operations' operating margin.

Several factors are designed to mitigate our risks from the increased concentration of credit that has resulted from deregulation. In addition to the security support described above, Atlanta Gas Light bills intrastate delivery service to Marketers in advance rather than in arrears. We accept credit support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers and corporate guarantees from investment-grade entities. The RMC reviews the adequacy of credit support coverage, credit rating profiles of credit support providers and payment status of each Marketer on a monthly basis. We believe that adequate policies and procedures have been put in place to properly quantify, manage and report on Atlanta Gas Light's credit risk exposure to Marketers.

Atlanta Gas Light also faces potential credit risk in connection with assignments to Marketers of interstate pipeline transportation and storage capacity. Although Atlanta Gas Light assigns this capacity to Marketers, in the event that a Marketer fails to pay the interstate pipelines for the capacity, the interstate pipelines would in all likelihood seek repayment from Atlanta Gas Light. The fact that some of the interstate pipelines require Marketers to maintain security for their obligations to the interstate pipelines arising out of the assigned capacity somewhat mitigates this risk.

Wholesale Services

Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. Sequent also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When we are engaged in more than one outstanding derivative transaction with the same counterparty and we also have a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of our credit risk. Sequent also uses other netting agreements with certain counterparties with whom we conduct significant transactions.

Master netting agreements enable Sequent to net certain assets and liabilities by counterparty. Sequent also nets across product lines and against cash collateral provided the master netting and cash collateral agreements include such provisions. Additionally, Sequent may require counterparties to pledge additional collateral when deemed necessary. We conduct credit evaluations and obtain appropriate internal approvals for our counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, we require credit enhancements by way of guaranty, cash deposit or letter of credit for transaction counterparties that do not meet the minimum ratings threshold.

Sequent, which provides services to Marketers and utility and industrial customers, also has a concentration of credit risk as measured by its 30-day receivable exposure plus forward exposure. As of December 31, 2004, Sequent's top 20 counterparties represented approximately 57% of the total counterparty exposure of $328 million, derived by adding the top 20 counterparties' exposures divided by the total of Sequent's counterparties' exposures.

As of December 31, 2004, Sequent's counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A- compared to BBB at December 31, 2003. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty.

To arrive at the weighted average credit rating, each counterparty's assigned internal rating is multiplied by the counterparty's credit exposure and summed for all counterparties. That sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following tables show Sequent's commodity receivable and payable positions as of December 31, 2004 and 2003:

Gross receivables

In millions	As of Dec 31, 2004	As of Dec 31, 2003	Change
Receivables with netting agreements in place:			
Counterparty is investment grade	**$378**	$282	$ 96
Counterparty is non-investment grade	**36**	13	23
Counterparty has no external rating	**78**	9	69
Receivables without netting agreements in place:			
Counterparty is investment grade	**16**	15	1
Counterparty is non-investment grade	**6**	—	6
Counterparty has no external rating	**—**	—	—
Amount recorded on balance sheet	**$514**	$319	$195

Gross payables

In millions	As of Dec 31, 2004	As of Dec 31, 2003	Change
Payables with netting agreements in place:			
Counterparty is investment grade	**$291**	$206	$ 85
Counterparty is non-investment grade	**45**	31	14
Counterparty has no external rating	**139**	45	94
Payables without netting agreements in place:			
Counterparty is investment grade	**40**	29	11
Counterparty is non-investment grade	**6**	3	3
Counterparty has no external rating	**—**	15	(15)
Amount recorded on balance sheet	**$521**	$329	$192

Energy Investments

SouthStar has established the following credit guidelines and risk management practices for each customer type:

- SouthStar scores firm residential and small commercial customers using a national reporting agency and enrolls, without security, only those customers that meet or exceed SouthStar's credit threshold.
- SouthStar investigates potential interruptible and large commercial customers through reference checks, review of publicly available financial statements and review of commercially available credit reports.
- SouthStar assigns physical wholesale counterparties an internal credit rating and credit limit prior to entering into a physical transaction based on their Moody's, S&P and Fitch rating, commercially available credit reports and audited financial statements.

STATEMENTS OF CONSOLIDATED INCOME

In millions, except per share amounts	2004	2003	2002
		Years ended December 31,	
Operating revenues	**$1,832**	$ 983	$ 877
Operating expenses			
Cost of gas	**994**	339	268
Operation and maintenance	**377**	283	274
Depreciation and amortization	**99**	91	89
Taxes other than income taxes	**30**	28	29
Total operating expenses	**1,500**	741	660
Gain on sale of Caroline Street campus	**—**	16	—
Operating income	**332**	258	217
Equity in earnings of SouthStar	**—**	46	27
Other (loss) income	**—**	(6)	3
Minority interest	**(18)**	—	—
Interest expense	**(71)**	(75)	(86)
Earnings before income taxes	**243**	223	161
Income taxes	**90**	87	58
Income before cumulative effect of change in accounting principle	**153**	136	103
Cumulative effect of change in accounting principle, net of $5 in taxes	**—**	(8)	—
Net income	**$ 153**	$ 128	$ 103
Basic earnings per common share:			
Income before cumulative effect of change in accounting principle	**$ 2.30**	$ 2.15	$1.84
Cumulative effect of change in accounting principle	**—**	(0.12)	—
Basic earnings per common share	**$ 2.30**	$ 2.03	$1.84
Fully diluted earnings per common share:			
Income before cumulative effect of change in accounting principle	**$ 2.28**	$ 2.13	$1.82
Cumulative effect of change in accounting principle	**—**	(0.12)	—
Fully diluted earnings per common share	**$ 2.28**	$ 2.01	$1.82
Weighted average number of common shares outstanding:			
Basic	**66.3**	63.1	56.1
Fully diluted	**67.0**	63.7	56.6

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS — ASSETS

In millions	As of Dec 31, 2004	As of Dec 31, 2003
Current assets		
Cash and cash equivalents	$ 49	$ 17
Receivables		
Energy marketing	514	319
Gas	217	65
Other	21	12
Less allowance for uncollectible accounts	(15)	(2)
Total receivables	737	394
Income tax receivable	29	—
Unbilled revenues	152	40
Inventories		
Natural gas stored underground	320	198
Other	12	12
Total inventories	332	210
Energy marketing and risk management assets	38	13
Unrecovered environmental remediation costs — current portion	27	24
Unrecovered pipeline replacement program costs — current portion	24	22
Unrecovered seasonal rates	11	11
Other current assets	58	11
Total current assets	1,457	742
Property, plant and equipment		
Property, plant and equipment	4,615	3,390
Less accumulated depreciation	1,437	1,045
Property, plant and equipment — net	3,178	2,345
Deferred debits and other assets		
Goodwill	354	184
Unrecovered pipeline replacement program costs	337	410
Unrecovered environmental remediation costs	173	155
Investments in equity interests	14	101
Unrecovered postretirement benefit costs	14	9
Other	113	26
Total deferred debits and other assets	1,005	885
Total assets	$5,640	$3,972

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS — LIABILITIES AND CAPITALIZATION

In millions, except share amounts	As of Dec 31, 2004	As of Dec 31, 2003
Current liabilities		
Energy marketing trade payable	**$ 521**	$ 329
Short-term debt	**334**	306
Accounts payable — trade	**207**	74
Accrued pipeline replacement program costs — current portion	**85**	82
Customer deposits	**50**	19
Deferred purchased gas adjustment	**37**	30
Accrued interest	**28**	21
Accrued environmental remediation costs — current portion	**27**	40
Accrued wages and salaries	**23**	18
Energy marketing and risk management liabilities — current portion	**15**	17
Accrued taxes	**14**	15
Current portion of long-term debt	**—**	77
Other current liabilities	**136**	20
Total current liabilities	**1,477**	1,048
Accumulated deferred income taxes	**437**	376
Long-term liabilities		
Accrued pipeline replacement program costs	**242**	323
Accrued postretirement benefit costs	**58**	51
Accumulated removal costs	**94**	102
Accrued environmental remediation costs	**63**	43
Accrued pension obligations	**84**	39
Accrued pipeline demand charges	**38**	—
Other long-term liabilities	**30**	11
Total long-term liabilities	**609**	569
Deferred credits		
Unamortized investment tax credit	**20**	19
Regulatory tax liability	**12**	12
Other deferred credits	**41**	47
Total deferred credits	**73**	78
Commitments and contingencies (see Note 10)		
Minority interest	**36**	—
Capitalization		
Long-term debt	**1,623**	956
Common shareholders' equity, $5 par value; 750,000,000 shares authorized (see accompanying statements of consolidated common shareholders' equity)	**1,385**	945
Total capitalization	**3,008**	1,901
Total liabilities and capitalization	**$5,640**	$3,972

See Notes to Consolidated Financial Statements.

STATEMENTS OF CONSOLIDATED COMMON SHAREHOLDERS' EQUITY

In millions, except per share amounts	Common Stock Shares	Common Stock Amount	Premium on Common Stock	Earnings Reinvested	Other Comprehensive Income	Shares Held in Treasury and Trust	Total
Balance as of December 31, 2001	57.8	$289	$204	$237	$ (1)	$(39)	$ 690
Comprehensive income:							
Net income	–	–	–	103	–	–	103
Other comprehensive income (OCI) — loss resulting from unfunded pension obligation (net of tax benefit of $31)	–	–	–	–	(48)	–	(48)
Total comprehensive income							55
Dividends on common stock ($1.08 per share)	–	–	–	(61)	–	–	(61)
Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax benefit of $1)	–	–	6	–	–	20	26
Balance as of December 31, 2002	57.8	289	210	279	(49)	(19)	710
Comprehensive income:							
Net income	–	–	–	128	–	–	128
OCI — gain resulting from unfunded pension obligation (net of tax of $6)	–	–	–	–	8	–	8
Unrealized gain from equity investments hedging activities (net of tax)	–	–	–	–	1	–	1
Total comprehensive income							137
Dividends on common stock ($1.11 per share)	–	–	–	(70)	–	–	(70)
Issuance of common shares:							
Equity offering on February 14, 2003	6.7	32	105	–	–	–	137
Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax benefit of $2)	–	1	11	–	–	19	31
Balance as of December 31, 2003	64.5	322	326	337	(40)	–	945
Comprehensive income:							
Net income	–	–	–	**153**	–	–	**153**
OCI — loss resulting from unfunded pension obligation (net of tax benefit of $7)	–	–	–	–	**(11)**	–	**(11)**
Unrealized gain from hedging activities (net of tax of $2)	–	–	–	–	**4**	–	**4**
Other	–	–	–	–	**1**	–	**1**
Total comprehensive income							**147**
Dividends on common stock ($1.15 per share)	–	–	–	**(75)**	–	–	**(75)**
Issuance of common shares:							
Equity offering on November 24, 2004	**11.0**	**55**	**277**	–	–	–	**332**
Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax benefit of $5)	**1.2**	**7**	**29**	–	–	–	**36**
Balance as of December 31, 2004	**76.7**	**$384**	**$632**	**$415**	**$(46)**	**$ –**	**$1,385**

See Notes to Consolidated Financial Statements.

STATEMENTS OF CONSOLIDATED CASH FLOWS

	Years ended December 31,		
In millions	2004	2003	2002
Cash flows from operating activities			
Net income	**$ 153**	$ 128	$ 103
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization	**99**	91	89
Deferred income taxes	**81**	55	82
Cumulative effect of change in accounting principle	**—**	13	—
Cash received from equity interests	**—**	40	—
Equity in earnings of unconsolidated subsidiaries	**(2)**	(47)	(27)
Gain on sale of Caroline Street campus	**—**	(16)	—
Change in risk management assets and liabilities	**(27)**	(1)	(3)
Changes in certain assets and liabilities			
Payables	**247**	61	244
Environmental remediation costs — net	**(13)**	(6)	(18)
Inventories	**(28)**	(91)	42
Receivables	**(264)**	(67)	(269)
Other — net	**41**	(38)	43
Net cash flow provided by operating activities	**287**	122	286
Cash flows from investing activities			
Acquisition of NUI, net of cash acquired	**(116)**	—	—
Property, plant and equipment expenditures	**(264)**	(158)	(187)
Acquisition of Jefferson Island	**(90)**	—	—
Purchase of Dynegy's 20% ownership interest in SouthStar	**—**	(20)	—
Cash received from sale of Caroline Street campus	**—**	23	—
Sale of US Propane	**31**	—	—
Cash received from equity interests	**—**	2	27
Other	**17**	8	(1)
Net cash flow used in investing activities	**(422)**	(145)	(161)
Cash flows from financing activities			
Issuances of senior notes	**450**	225	—
Equity offering	**332**	137	—
Sale of treasury shares	**—**	19	20
Sale of common stock	**36**	12	6
Dividends paid on common shares	**(75)**	(70)	(53)
Net payments and borrowings of short-term debt	**(480)**	(82)	4
Distribution to minority interest	**(14)**	—	—
Payments of Medium-Term notes	**(82)**	(207)	(93)
Other	**—**	(3)	(8)
Net cash flow provided by (used in) financing activities	**167**	31	(124)
Net increase in cash and cash equivalents	**32**	8	1
Cash and cash equivalents at beginning of period	**17**	9	8
Cash and cash equivalents at end of period	**$ 49**	$ 17	$ 9
Cash paid during the period for			
Interest (net of allowance for funds used during construction)	**$ 50**	$ 60	$ 73
Income taxes	**27**	23	15

See Notes to Consolidated Financial Statements.

Note 1
ACCOUNTING POLICIES AND METHODS OF APPLICATION

GENERAL

AGL Resources Inc. is an energy services holding company that conducts substantially all its operations through its subsidiaries. Unless the context requires otherwise, references to "we," "us," "our" or the "company" are intended to mean consolidated AGL Resources Inc. and its subsidiaries (AGL Resources). We have prepared the accompanying consolidated financial statements under the rules of the Securities and Exchange Commission (SEC).

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies, including state public service commissions and the SEC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operation of regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. On April 1, 2004, we received approval from the SEC, under the Public Utility Holding Company Act of 1935 (PUHCA), for the renewal of our financing authority to issue securities through April 2007.

BASIS OF PRESENTATION

Our consolidated financial statements as of and for the periods ended December 31, 2004 include our accounts, the accounts of our majority-owned and controlled subsidiaries and the accounts of variable interest entities for which we are the primary beneficiary. This means that our accounts are combined with the subsidiaries' accounts. Certain amounts from prior periods have been reclassified to conform to the current-period presentation. Any intercompany profits and transactions between segments have been eliminated in consolidation; however, intercompany profits are not eliminated when such amounts are probable of recovery under the affiliates' rate regulation process. On November 30, 2004, we completed our acquisition of NUI Corporation (NUI); for more information see Note 2.

As of January 1, 2004, our consolidated financial statements include the accounts of SouthStar Energy Services LLC (SouthStar), a variable interest entity of which we are the primary beneficiary. Prior to January 1, 2004, we accounted for our 70% noncontrolling financial ownership interest in SouthStar using the equity method of accounting. Under the equity method, our ownership interest in SouthStar was reported as an investment within our consolidated balance sheets, and our share of SouthStar's earnings was reported in our consolidated statements of income as a component of other income. We utilize the equity method to account for and report investments where we exercise significant influence but do not control and where we are not the primary beneficiary as defined by Financial Accounting Standards Board (FASB) Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 was revised in December 2003 (FIN 46R); consequently, as of January 1, 2004, we consolidated all SouthStar's accounts with our subsidiaries' accounts and eliminated any intercompany balances between segments. For more discussion of FIN 46R and the impact of its adoption on our consolidated financial statements, see Note 3.

Our equity method investments generally include entities where we have a 20% to 50% voting interest. In 2004, our investment in equity interests was composed of our 50% ownership in Saltville Gas Storage Company, LLC, a joint venture with a subsidiary of Duke Energy Corporation to develop a high-deliverability natural gas storage facility in Saltville, Virginia.

Cash and Cash Equivalents

Our cash and cash equivalents consist primarily of cash on deposit, money market accounts and certificates of deposit with original maturities of three months or less.

Receivables and Allowance for Uncollectible Accounts

Our receivables consist of natural gas sales and transportation services billed to residential, commercial, industrial and other customers. Customers are billed monthly and accounts receivable are due within 30 days. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collection experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances that could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

INVENTORIES

Our gas inventories are accounted for using the weighted average cost method. Materials and supplies inventories are stated at the lower of average cost or market. At December 31, 2004, Sequent's natural gas inventory for reservoir and salt dome storage was recorded on an accrual basis. At December 31, 2004, Sequent's inventory held under park and loan arrangements was recorded at the lower of average cost or market. However, for those park and loan arrangements that are payable or to be repaid at determinable dates to third parties, the inventory was recorded at fair value.

In Georgia's competitive environment, Marketers—that is, marketers who are certificated by the Georgia Public Service Commission (Georgia Commission) to sell retail natural gas in Georgia—including the Atlanta Gas Light Company (Atlanta Gas Light) marketing affiliate SouthStar, began selling natural gas in 1998 to firm end-use customers at market-based prices. Part of the unbundling process, which resulted from deregulation that provides for this competitive environment, is the assignment to Marketers of certain pipeline services that Atlanta Gas Light has under contract. Atlanta Gas Light assigns, on a monthly basis, the majority of the pipeline storage services that it has under contract to Marketers, along with a corresponding amount of inventory.

PROPERTY, PLANT AND EQUIPMENT

Distribution Operations

Property, plant and equipment expenditures consist of property and equipment that is in use, being held for future use and under construction. It is reported at its original cost, which includes

- material and labor
- contractor costs
- construction overhead costs
- an allowance for funds used during construction

Property retired or otherwise disposed of is charged to accumulated depreciation.

Wholesale Services, Energy Investments and Corporate

Property, plant and equipment expenditures include property that is in use and under construction, and is reported at cost. A gain or loss is recorded for retired or otherwise disposed of property.

Goodwill

We adopted Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets" (SFAS 142), effective October 1, 2001. Under SFAS 142, goodwill is no longer amortized. SFAS 142 further requires an initial goodwill impairment assessment in the year of adoption and annual impairment tests thereafter. We have included $354 million of goodwill in our consolidated balance sheets, of which $157 million is related to our acquisition of NUI in November 2004 (see Note 2 for further details), $176 million is related to our acquisition of Virginia Natural Gas, Inc. (Virginia Natural Gas) in 2000, $14 million is related to our acquisition of Jefferson Island Storage & Hub, LLC (Jefferson Island) in October 2004 and $7 million is related to our acquisition of Chattanooga Natural Gas Company (Chattanooga Gas) in 1988.

We annually assess goodwill for impairment as of our fiscal year end and have not recognized any impairment charges for the years ended December 31, 2004, 2003 and 2002. We also assess goodwill for impairment if events or changes in circumstances may indicate an impairment of goodwill exists. We conduct this assessment principally through a review of financial results, changes in state and federal legislation and regulation, and the periodic regulatory filings for our regulated utilities.

ACCUMULATED DEFERRED INCOME TAXES

The reporting of our assets and liabilities for financial accounting purposes differs from the reporting for income tax purposes. The principal differences between net income and taxable income relate to the timing of deductions, primarily due to the benefits of tax depreciation since assets are generally depreciated for tax purposes over a shorter period of time than for book purposes. The tax effects of depreciation and other differences in those items are reported as deferred income tax assets or liabilities in our consolidated balance sheets. Investment tax credits of approximately $20 million were previously deducted for income tax purposes for Atlanta Gas Light, Chattanooga Gas and Elizabethtown Gas Company (Elizabethtown Gas), and have been deferred for financial accounting purposes and are being amortized as credits to income over the estimated lives of the related properties in accordance with regulatory requirements.

REVENUES

Distribution Operations

Revenues are recorded when services are provided to customers. Those revenues are based on rates approved by the regulatory state commissions of our utilities.

As required by the Georgia Commission, in July 1998, Atlanta Gas Light began billing Marketers for each residential, commercial and industrial customer's distribution costs in equal monthly installments. As required by the Georgia Commission, effective February 1, 2001, Atlanta Gas Light implemented a seasonal rate design for the calculation of each residential customer's annual straight-fixed-variable (SFV) capacity charge, which is billed to Marketers and reflects the historic volumetric usage pattern for the entire residential class. Generally, this change results in residential customers being billed by Marketers for a higher capacity charge in the winter months and a lower charge in the summer months. This requirement has an operating cash flow impact but does not change revenue recognition. As a result, Atlanta Gas Light continues to recognize its residential SFV capacity revenues for financial reporting purposes in equal monthly installments.

Any difference between the billings under the seasonal rate design and the SFV revenue recognized is deferred and reconciled to actual billings on an annual basis. Atlanta Gas Light had unrecovered seasonal rates of approximately $11 million as of December 31, 2004 and 2003 (included as current assets in the consolidated balance sheets), related to the difference between the billings under the seasonal rate design and the SFV revenue recognized.

The Virginia Natural Gas and Chattanooga Gas rate structures include volumetric rate designs that allow recovery of costs through gas usage. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Virginia Natural Gas and Chattanooga Gas recognize sales revenues from residential and certain commercial and industrial customers on the basis of scheduled meter readings. In addition, revenues are recorded for estimated deliveries of gas, not yet billed to these customers, from the meter reading date to the end of the accounting period. These are included in the consolidated balance sheets as unbilled revenue. For other commercial and industrial customers and all wholesale customers, revenues are based upon actual deliveries to the end of the period.

The tariffs for Elizabethtown Gas, Virginia Natural Gas and Chattanooga Gas contain weather normalization adjustments (WNA) that largely mitigate the impact of unusually cold or warm weather on customer billings and operating margin. The WNA's purpose is to reduce the effect of weather on customer bills by reducing bills when winter weather is colder than normal and increasing bills when weather is warmer than normal.

Wholesale Services

Wholesale services' revenues are recorded when services are provided to customers. Intercompany profits from sales between segments are eliminated in the corporate segment and are recognized as goods or services sold to end-use customers. Transactions that qualify as derivatives under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133), are recorded at fair value with changes in fair value recorded as revenues in our statements of income.

COST OF GAS

We charge our utility customers for the natural gas they consume using purchased gas adjustment (PGA) mechanisms set by the state regulatory agencies. Under the PGA, we defer (that is, include as a current asset or liability in the consolidated balance sheets and exclude from the statements of consolidated income) the difference between the actual cost of gas and what is collected from customers in a given period. The deferred amount is either billed or refunded to our customers.

STOCK-BASED COMPENSATION

We have several stock-based employee compensation plans and account for these plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25), and related interpretations. For our stock option plans, we generally do not reflect stock-based employee compensation cost in net income, as options for those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. For our stock appreciation rights, we reflect stock-based employee compensation cost based on the fair value of our common stock at the balance sheet date since these awards constitute a variable plan under APB 25.

The following table illustrates the effect on our net income and earnings per share had we applied the fair value recognition provisions of SFAS 123, "Accounting for Stock-Based Compensation" (SFAS 123):

In millions, except per share amounts	2004	2003	2002
Net income, as reported	**$ 153**	$ 128	$ 103
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effect	**(1)**	(1)	(2)
Pro-forma net income	**$ 152**	$ 127	$ 101
Earnings per share			
Basic — as reported	**$2.30**	$2.03	$1.84
Basic — pro-forma	**$2.28**	$2.02	$1.80
Fully diluted — as reported	**$2.28**	$2.01	$1.82
Fully diluted — pro-forma	**$2.26**	$2.00	$1.79

DEPRECIATION EXPENSE

Depreciation expense for distribution operations is computed by applying composite, straight-line rates (approved by the state regulatory agencies) to the investment of depreciable property. Excluding the utilities acquired from NUI, distribution operations' composite straight-line depreciation rate for depreciable property excluding transportation equipment was approximately 2.6% during 2004, 2.7% during 2003 and 2.8% during 2002. The composite, straight-line rate for the utilities acquired from NUI was 3.25%. As of May 1, 2002, the Georgia Commission required a decrease of depreciation rates for Atlanta Gas Light, which decreased depreciation expense by $6 million in 2002 and approximately $10 million annually on a going forward basis. We depreciate transportation equipment on a straight-line basis over a period of 5 to 10 years. We compute depreciation expense for other segments on a straight-line basis over a period of 1 to 35 years.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

The applicable state regulatory agencies authorize Atlanta Gas Light, Elizabethtown Gas and Chattanooga Gas to record the cost of debt and equity funds as part of the cost of construction projects in our consolidated balance sheets and as AFUDC in the statements of consolidated income. The Georgia Commission has authorized a rate of 9.16%, the New Jersey Board of Public Utilities (NJBPU) has authorized a rate of 7.60% and the Tennessee Regulatory Authority (Tennessee Authority) has authorized a rate of 9.08%. The capital expenditures of our other regulated utilities do not qualify for AFUDC treatment.

COMPREHENSIVE INCOME

Our comprehensive income includes net income plus other comprehensive income (OCI), which includes other gains and losses affecting shareholders' equity that accounting principles generally accepted in the United States (GAAP) exclude from net income. Such items consist primarily of unrealized gains and losses on certain derivatives and minimum pension liability adjustments.

In 2004, our OCI decreased $6 million as a result of an $11 million increase in our unfunded pension obligation, net of a $7 million income tax benefit, which was offset by changes in the fair value of derivatives designated as cash flow hedges at SouthStar of $4 million. For more information on SouthStar's derivative financial instruments, see Note 4.

In 2003, our OCI increased $9 million as a result of an $8 million decrease in our unfunded pension obligation and $1 million for our 70% ownership interest in SouthStar's unrealized gain associated with its cash flow hedges. In 2002, our OCI decreased by $48 million, net of income tax benefit of $31 million, as a result of an increase in our unfunded pension obligation.

EARNINGS PER COMMON SHARE

We compute basic earnings per common share by dividing our income available to common shareholders by the daily weighted average number of common shares outstanding. Fully diluted earnings per common share reflect the potential reduction in earnings per common share that could occur when potentially dilutive common shares are added to common shares outstanding.

We derive our potentially dilutive common shares by calculating the number of shares issuable under performance units and stock options. The future issuance of shares underlying the performance units depends on the satisfaction of certain performance criteria. The future issuance of shares underlying the outstanding stock options depends on whether the exercise prices of the stock options are less than the average market price of the common shares for the respective periods. No items are antidilutive. The following table shows the calculation of our fully diluted earnings per share for the periods presented if performance units currently earned under the plan ultimately vest and if stock options currently exercisable at prices below the average market prices are exercised:

In millions	2004	2003	2002
Denominator for basic earnings per share[1]	**66.3**	63.1	56.1
Assumed exercise of potential common shares	**0.7**	0.6	0.5
Denominator for fully diluted earnings per share	**67.0**	63.7	56.6

[1] Daily weighted average shares outstanding.

USE OF ACCOUNTING ESTIMATES

The preparation of our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include our regulatory accounting, the allowance for doubtful accounts, allowance for contingencies, pipeline replacement program accruals, environmental liability accruals, unbilled revenue recognition, pension obligations, derivative and hedging activities and purchase price allocations. Actual results could differ from those estimates.

Note 2
ACQUISITIONS
NUI CORPORATION

On November 30, 2004, we acquired all the outstanding shares of NUI for approximately $218 million, incurred $7 million of transaction costs and repaid $500 million of NUI's outstanding short-term debt. At closing, NUI had $709 million in debt and approximately $109 million of cash on its balance sheet (including the return of an interest escrow balance), bringing the net value of the acquisition to approximately $825 million. In connection with the acquisition, we incurred $23 million in employee-related restructuring charges, which include $16 million in severance costs, $4 million in change in control payments to certain NUI executives and the NUI Board of Directors, and $3 million of employee retention and relocation costs. The acquisition significantly expands our existing natural gas utilities, storage and pipeline businesses.

We funded the purchase price with a portion of the proceeds from our November 2004 common stock offering and proceeds from short-term borrowings under our commercial paper program. Additionally, NUI Utilities, Inc., a wholly owned subsidiary of NUI, had outstanding, at closing, $199 million of indebtedness pursuant to Gas Facility Revenue Bonds and $10 million in capital leases.

Our allocation of the purchase price is preliminary and is subject to change. The preliminary nature is a result of the timing of the acquisition, which occurred late in our fourth quarter. The amount currently allocated to property, plant and equipment represents our estimate of the fair value of the assets acquired. We based that estimate on a preliminary independent valuation counselor's report, which is expected to be finalized during the first quarter of 2005. The following table summarizes the fair values of the assets acquired and liabilities assumed on November 30, 2004:

In millions	Preliminary Fair Value
Purchase price	$ 825
Current assets	299
Property, plant and equipment	612
Other long-term assets	117
Goodwill	157
Current liabilities excluding debt	(108)
Short-term debt and capital leases	(502)
Long-term debt and capital leases	(207)
Other long-term liabilities	(143)
Equity	225

The excess of the purchase price over the fair value of the identifiable net assets acquired of $157 million was allocated to goodwill. We believe the acquisition resulted in the recognition of goodwill primarily because of the strength of NUI's underlying assets and the synergies and opportunities in the regulated utilities. Goodwill is not deductible for income tax purposes.

The table below reflects the unaudited pro-forma results of AGL Resources and NUI for the years ended December 31, 2004 and 2003 as if the acquisition and related financing had taken place on January 1. The pro-forma results are not necessarily indicative of the results that would have occurred if the acquisition had been in effect for the periods presented. In addition, the pro-forma results are not intended to be a projection of future results and do not reflect any synergies that might be achieved from combining the operations or eliminating significant expenses that NUI incurred in its last year of operations. Our results of operations for 2004 include one month of the acquired operations of NUI.

In millions, except per share amounts	2004	2003
Operating revenue	**$2,343**	$1,630
Income before cumulative effect of change in accounting principle	**105**	88
Net income	**105**	74
Net income per fully diluted share	**1.44**	1.05

JEFFERSON ISLAND

We acquired Jefferson Island from American Electric Power in October 2004 for $90 million, which included approximately $9 million of working gas inventory. We funded the acquisition with a portion of the net proceeds we received from our November 2004 common stock offering and borrowings.

Note 3

RECENT ACCOUNTING PRONOUNCEMENTS

ADOPTED IN 2004

FIN 46

FIN 46 requires the primary beneficiary of a variable interest entity's activities to consolidate the variable interest entity. The primary beneficiary is the party that absorbs a majority of the expected losses and/or receives a majority of the expected residual returns of the variable interest entity's activities.

In December 2003, the FASB revised FIN 46, delaying the effective dates for certain entities created before February 1, 2003, and making other amendments to clarify application of the guidance. For potential variable interest entities other than any special purpose entities, the FASB required FIN 46R to be applied no later than the end of the first fiscal year or interim reporting period ending after March 15, 2004. FIN 46R also requires certain disclosures of an entity's relationship with variable interest entities. We adopted FIN 46R effective January 1, 2004, resulting in the consolidation of SouthStar's accounts in our consolidated financial statements and the deconsolidation of the accounts related to our Trust Preferred Securities. FIN 46R also requires certain disclosures of an entity's relationship with variable interest entities.

Notes Payable to Trusts and Trust Preferred Securities In June 1997 and March 2001, we established AGL Capital Trust I and AGL Capital Trust II (Trusts) to issue our Trust Preferred Securities. The Trusts are considered to be special purpose entities under FIN 46 and FIN 46R since

- our equity in the Trusts is not considered to be sufficient to allow the Trusts to finance their own activities
- our equity investment is not considered to be at risk since the equity amounts were financed by the Trusts

Under FIN 46 (prior to the revision in FIN 46R), we concluded that we were the primary beneficiary of the Trusts because the Trust Preferred Securities are publicly traded and widely held, and no one party would absorb a majority of any expected losses of the Trusts. In addition, our loan agreements with the Trusts include call options that capture declining interest rates by enabling us to call the preferred securities at par and thereby capturing the majority of the residual returns in the Trusts. Accordingly, at December 31, 2003, the accounts of the Trusts were included in our consolidated financial statements.

The revisions in FIN 46R included specific guidance that instruments such as the call options included in our loan agreements with the Trusts do not constitute variable interests and should not be considered in the determination of the primary beneficiary. As a result, as of January 1, 2004 (when we adopted FIN 46R), we were required to exclude the accounts of the Trusts from our consolidated financial statements and to classify amounts payable to the Trusts as "Notes payable to Trusts" within long-term debt in our consolidated balance sheets as of December 31, 2004.

Due to deconsolidation of the Trusts, we included in our consolidated balance sheets at December 31, 2004, an asset of approximately $10 million representing our investment in the Trusts and a note payable to the Trusts totaling approximately $235 million, net of an interest rate swap of $3 million. We also removed $222 million related to the Trust Preferred Securities issued by the Trusts. The notes payable represent the loan payable to fund our investments in the Trusts of $10 million and the amounts due to the Trusts from the proceeds received from their issuances of Trust Preferred Securities of $222 million.

Consolidation of SouthStar In 1998 a joint venture, SouthStar, was formed by our wholly owned subsidiary, Georgia Natural Gas Company, Piedmont Natural Gas Company, Inc. (Piedmont) and Dynegy Inc. (Dynegy) to market natural gas and related services to retail customers, principally in Georgia. SouthStar, which operates under the trade name Georgia Natural Gas, competes with other energy marketers, including Marketers in Georgia, to provide natural gas and related services to customers in Georgia and the Southeast. In March 2003, we purchased Dynegy's 20% ownership interest in a transaction that for accounting purposes had an effective date of February 18, 2003. We currently own a noncontrolling 70% financial interest in SouthStar and Piedmont owns the remaining 30%. Our 70% interest is noncontrolling because all significant management decisions require approval by both owners.

In March 2004, we executed an amended and restated partnership agreement with Piedmont that calls for SouthStar's earnings starting in 2004 to be allocated 75% to our subsidiary and 25% to Piedmont. Consequently, as of January 1, 2004 we consolidated all SouthStar's accounts with our subsidiaries' accounts and eliminated any intercompany balances between segments. We recorded Piedmont's portion of SouthStar's earnings as a minority interest in our consolidated statements of income, and we recorded Piedmont's portion of SouthStar's capital as a minority interest in our consolidated balance sheet. For all periods prior to February 18, 2003, SouthStar's earnings were allocated based on our 50% ownership interests in those periods. We determined that SouthStar is a variable interest entity as defined in FIN 46R because:

- Our equal voting rights with Piedmont are not proportional to our economic obligation to absorb 75% of any losses or residual returns from SouthStar.
- SouthStar obtains substantially all its transportation capacity for delivery of natural gas through our wholly owned subsidiary, Atlanta Gas Light.

As of December 31, 2003, we did not consolidate SouthStar in our financial statements because it did not meet the definition of a variable interest entity under FIN 46. FIN 46R added the following conditions for determining whether an entity is a variable interest entity:

- The voting rights of some investors are not proportional to their obligations to absorb the expected losses of the entity, their rights to receive the expected residual returns of the entity, or both.
- Substantially all the entity's activities (for example, purchasing products and additional capital) either involve or are conducted on behalf of an investor that has disproportionately fewer voting rights.

However, as SouthStar's results of operations and financial condition were material in 2002 and 2003 to our financial results, we present below the summarized amounts for 100% of SouthStar. These results are not comparable with our earnings or losses from SouthStar in those prior periods, which we reported as other income (loss) in our statements of consolidated income, as those amounts were reported based on our ownership percentage.

In millions	Dec 31, 2003
Balance sheet	
Current assets	$174
Noncurrent assets	2
Current liabilities	75
Noncurrent liabilities	—

In millions	2003	2002
Income statement		
Revenues	$746	$630
Operating margin	124	115
Operating income	63	41
Net income from continuing operations	63	42

ISSUED BUT NOT YET ADOPTED IN 2004

In December 2004, the FASB issued SFAS No. 123(R), "Accounting for Stock Based Compensation" (SFAS 123R). SFAS 123R revises the guidance in SFAS 123 and supersedes APB 25, and its related implementation guidance. SFAS 123R focuses primarily on the accounting for share-based payments to employees in exchange for services, and it requires a public entity to measure and recognize compensation cost for these payments. Our share-based payments are typically in the form of stock option and restricted stock awards. The primary change in accounting is related to the requirement to recognize compensation cost for stock option awards that was not recognized under APB 25.

Compensation cost will be measured based on the fair value of the equity or liability instruments issued. For stock option awards, fair value would be estimated using an option pricing model such as the Black-Scholes model. SFAS 123R becomes effective as of the first interim or annual reporting period that begins after June 15, 2005, and therefore we will adopt SFAS 123R in the third quarter of 2005. We expect to recognize approximately $1 million of compensation cost during the last six months of 2005 related to our stock option awards. For a discussion of our stock-based compensation plans and agreements, see Note 7.

Note 4
RISK MANAGEMENT

Our risk management activities are monitored by our Risk Management Committee (RMC). The RMC consists of senior management and is charged with the review and enforcement of our risk management activities. Our risk management policies limit the use of derivative financial instruments and physical transactions within predefined risk tolerances associated with pre-existing or anticipated physical natural gas sales and purchases and system use and storage. We use the following derivative financial instruments and physical transactions to manage commodity price risks:

- forward contracts
- futures contracts
- options contracts
- financial swaps
- storage and transportation capacity transactions

INTEREST RATE SWAPS

To maintain an effective capital structure, it is our policy to borrow funds using a mix of fixed-rate debt and variable-rate debt. We have entered into interest rate swap agreements through our wholly owned subsidiary, AGL Capital Corporation (AGL Capital), for the purpose of hedging the interest rate risk associated with our fixed-rate and variable-rate debt obligations. We designated these interest rate swaps as fair value hedges and accounted for them using the "shortcut" method prescribed by SFAS 133, which allows us to designate derivatives that hedge exposure to changes in the fair value of a recognized asset or liability. We record the gain or loss on fair value hedges in earnings in the period of change, together with the offsetting loss or gain on the hedged item attributable to the risk being hedged. The effect of this accounting is to reflect in the interest expense line item in the statement of consolidated income, only that portion of the hedge that is ineffective in achieving offsetting changes in fair value.

Accordingly, we adjust the carrying value of each interest rate swap to its fair value at the end of each period, with an offsetting and equal adjustment to the carrying value of the debt securities whose fair value is being hedged. Consequently, our earnings are not affected negatively or positively with changes in fair value of the interest swaps each quarter.

In March 2004, we adjusted our fixed- to variable-rate obligations and terminated an interest rate swap on $100 million of the principal amount of our 4.45% Senior Notes due 2013. Additionally, as of March 31, 2004 and in connection with the deconsolidation of the Trusts, we redesignated the interest rate swaps on the Trust Preferred Securities as a fair value hedge of our notes payable to Trusts.

As of December 31, 2004, a notional principal amount of $175 million of these agreements effectively converted the interest expense associated with a portion of our senior notes and notes payable to Trusts from fixed rates to variable rates based on an interest rate equal to the London Interbank Offered Rate (LIBOR), plus a spread determined at the swap date. The fair value of these interest rate swaps was recorded as an asset of $1 million at December 31, 2004 and a liability of $4 million at December 31, 2003. For more information on the effective rates and maturity dates of our interest rate swaps, see Note 8.

In the third quarter of 2004, in anticipation of our $250 million Senior Note offering, we executed two treasury lock derivative instruments totaling $200 million to hedge our exposure to the potential increase in interest rates. These derivative instruments locked in a 10-year U.S. treasury rate of 4.45%. The rate on the 10-year treasury notes declined subsequent to the execution of these instruments and the pricing of our senior notes was set on a U.S. treasury rate of 4.81%. As a result, we terminated these derivative instruments and made an $8 million settlement payment to our counterparties, which we will amortize over the next 10 years through interest expense. The termination added approximately 30 basis points to the interest rate of our 6% Senior Notes.

COMMODITY-RELATED DERIVATIVE INSTRUMENTS

Elizabethtown Gas

Certain derivatives are utilized by Elizabethtown Gas for nontrading purposes to hedge the impact of market fluctuations on assets, liabilities and other contractual commitments. Pursuant to SFAS 133, such derivative products are marked-to-market each reporting period. Pursuant to regulatory requirements, realized gains and losses related to such derivatives are reflected in purchased gas costs and included in billings to customers. Unrealized gains and losses are reflected as a regulatory asset (loss) or liability (gain), as appropriate, on the consolidated balance sheet. As of December 31, 2004, Elizabethtown Gas had entered into New York Mercantile Exchange (NYMEX) futures contracts to purchase 9.7 billion cubic feet (Bcf) of natural gas at equivalent prices ranging from $3.609 to $8.291 per thousand cubic feet. Approximately 84% of these contracts have a duration of one year or less, and none of these contracts extend beyond October 2006.

Sequent Energy Management, L.P. (Sequent)

We are exposed to risks associated with changes in the market price of natural gas. Sequent uses derivative financial instruments to reduce our exposure to the risk of changes in the prices of natural gas. The fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all the financial instruments we utilize.

We attempt to mitigate substantially all the commodity price risk associated with Sequent's gas storage portfolio by locking in the economic margin at the time we enter into gas purchase transactions for our storage gas. We purchase gas for storage when the current market price we pay to buy gas plus the cost to store the gas is less than the market price we could receive in the future, resulting in a positive net profit margin. We use futures NYMEX contracts and other over-the-counter derivatives to sell gas at that future price to substantially lock in the profit margin we will ultimately realize when the stored gas is actually sold. These futures contracts meet the definition of a derivative under SFAS 133 and are recorded at fair value in our consolidated balance sheets, with changes in fair value recorded in earnings in the period of change. The purchase, storage and sale of natural gas are accounted for on an accrual basis rather than on the mark-to-market basis we utilize for the derivatives used to mitigate the commodity price risk associated with our storage portfolio. This difference in accounting will result in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

At December 31, 2004, our commodity-related derivative financial instruments represented purchases (long) of 521 Bcf and sales (short) of 550 Bcf with approximately 93% of these scheduled to mature in less than two years and the remaining 7% in three to nine years. Excluding the cumulative effect of a change in accounting principle in 2003, our unrealized gains were $22 million in 2004, $1 million in 2003 and $4 million in 2002.

SouthStar

The commodity-related derivative financial instruments (futures, options and swaps) used by SouthStar manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to utilize the most effective methods to reduce or eliminate the impacts of changing commodity prices. A significant portion of SouthStar's derivative transactions are designated as cash flow hedges under SFAS 133. Derivative gains or losses arising from cash flow hedges are recorded in OCI and are reclassified into earnings in the same period as the settlement of the underlying hedged item. Any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not perfectly offset the losses or gains on the hedged item, is recorded in our cost of gas on our consolidated income statement in the period in which it occurs. SouthStar currently has only minimal hedge ineffectiveness.

SouthStar's remaining derivative instruments do not meet the hedge criteria under SFAS 133; therefore, changes in the fair value of these derivatives are recorded in earnings in the period of change. At December 31, 2004, the fair values of these derivatives were reflected in our consolidated financial statements as an asset of $9 million and a liability of $2 million. The maximum maturity of open positions is less than one year and represents purchases and sales of 8 Bcf.

CONCENTRATION OF CREDIT RISK

Atlanta Gas Light

Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 10 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the nonpeak summer months and highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of natural gas. Atlanta Gas Light's tariff allows it to obtain security support in an amount equal to a minimum of two times a Marketer's highest monthly invoice.

Sequent

A concentration of credit risk exists at Sequent for amounts billed for services it provides to marketers and to utility and industrial customers. This credit risk is measured by 30-day receivable exposure plus forward exposure, which is highly concentrated in 20 of its customers. Sequent evaluates its counterparties using the Standard & Poor's Ratings Services (S&P) equivalent credit rating, which is determined by a process of converting the lower of the S&P or Moody's Investors Service (Moody's) rating to an internal rating ranging from 9.00 to 1.00, with 9.00 being equivalent to AAA/Aaa by S&P and Moody's and 1.00 being equivalent to D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of its financial ratios.

The weighted average credit rating is obtained by multiplying each counterparty's assigned internal rating by the counterparty's credit exposure and the individual results are then summed for all counterparties. That total is divided by the aggregate total counterparties' exposure. This numeric value is converted to an S&P equivalent. At December 31, 2004, Sequent's top 20 counterparties represented approximately 57% of the total counterparty exposure of $328 million, derived by adding the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures. Sequent's counterparties or the counterparties' guarantors had a weighted average S&P equivalent of an A- rating at December 31, 2004.

Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. When we are engaged in more than one outstanding derivative transaction with the same counterparty and we also have a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of our credit risk. Sequent also uses other netting agreements with certain counterparties with whom we conduct significant transactions.

Note 5

REGULATORY ASSETS AND LIABILITIES

We have recorded regulatory assets and liabilities in our consolidated balance sheets in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). Our regulatory assets and liabilities, and associated liabilities for our unrecovered pipeline replacement program (PRP) costs and unrecovered environmental remediation costs, are summarized in the table below:

In millions	Dec 31, 2004	Dec 31, 2003
Regulatory assets		
Unrecovered pipline replacement program (PRP) costs	**$361**	$432
Unrecovered environmental remediation costs	**200**	179
Unrecovered postretirement benefit costs	**14**	9
Unrecovered seasonal rates	**11**	11
Unrecovered PGA	**5**	—
Regulatory tax asset	**2**	3
Other	**20**	5
Total regulatory assets	**$613**	$639
Regulatory liabilities		
Accumulated removal costs	**$ 94**	$102
Unamortized investment tax credit	**20**	19
Deferred PGA	**37**	30
Regulatory tax liability	**14**	15
Other	**18**	3
Total regulatory liabilities	**183**	169
Associated liabilities		
PRP costs	**327**	405
Environmental remediation costs	**90**	83
Total associated liabilities	**417**	488
Total regulatory and associated liabilities	**$600**	$657

Our regulatory assets are recoverable through either rate riders or base rates specifically authorized by a state regulatory commission. Base rates are designed to provide both a recovery of cost and a return on investment during the period rates are in effect. As such, all our regulatory assets are subject to review by the respective state regulatory commission during any future rate proceedings. In the event that the provisions of SFAS 71 were no longer applicable, we would recognize a write-off of net regulatory assets (regulatory assets less regulatory liabilities) that would result in a charge to net income, which would be classified as an extraordinary item. However, although the gas distribution industry is becoming increasingly competitive, our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under SFAS 71 remains appropriate. It is also our opinion that all regulatory assets are recoverable in future rate proceedings, and therefore, we have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a rate rider.

All the regulatory assets included in the table above are included in base rates except for the unrecovered PRP costs, unrecovered environmental remediation costs and deferred PGA, which are recovered through specific rate riders. The rate riders that authorize recovery of unrecovered PRP costs and the deferred PGA include both a recovery of costs and a return on investment during the recovery period. We have two rate riders that authorize the recovery of unrecovered environmental remediation costs. The environmental remediation cost rate rider for Atlanta Gas Light only allows for recovery of the costs incurred and the recovery period occurs over the five years after the expense is incurred. Environmental remediation costs associated with the investigation and remediation of Elizabethtown Gas' remediation sites located in the state of New Jersey are recovered under a Remediation Adjustment Clause and include the carrying cost on unrecovered amounts not currently in rates.

The regulatory liabilities are refunded to ratepayers through a rate rider or base rates. If the regulatory liability is included in base rates, the amount is reflected as a reduction to the rate base in setting rates.

PIPELINE REPLACEMENT PROGRAM

The PRP, ordered by the Georgia Commission to be administered by Atlanta Gas Light, requires, among other things, that it replace all bare steel and cast iron pipe in its system in the state of Georgia within a 10-year period, beginning October 1, 1998. Atlanta Gas Light identified, and provided notice to the Georgia Commission of, 2,312 miles of pipe to be replaced. Atlanta Gas Light has subsequently identified an additional 188 miles of pipe subject to replacement under this program. If Atlanta Gas Light does not perform in accordance with this order, it will be assessed certain nonperformance penalties. October 1, 2004 marked the beginning of the seventh year of the 10-year PRP.

The order also provides for recovery of all prudent costs incurred in the performance of the program, which Atlanta Gas Light has recorded as a regulatory asset. Atlanta Gas Light will recover from end-use customers, through billings to Marketers, the costs related to the program net of any cost savings from the program. All such amounts will be recovered through a combination of SFV rates and a pipeline replacement revenue rider. The regulatory asset has two components:

- the costs incurred to date that have not yet been recovered through the rate rider
- the future expected costs to be recovered through the rate rider

Atlanta Gas Light has recorded a long-term regulatory asset of $337 million, which represents the expected future collection of both expenditures already incurred and expected future capital expenditures to be incurred through the remainder of the program. Atlanta Gas Light has also recorded a current asset of $24 million, which represents the expected amount to be collected from customers over the next 12 months. The amounts recovered from the pipeline replacement revenue rider during the last three years were

- $28 million in 2004
- $15 million in 2003
- $8 million in 2002

As of December 31, 2004, Atlanta Gas Light had recorded a current liability of $85 million, representing expected program expenditures for the next 12 months. Atlanta Gas Light anticipates that its capital expenditures for the PRP will end by June 30, 2008, unless we agree with the Georgia Commission to an extension of the program.

Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the PRP over the life of the assets. Operation and maintenance costs are expensed as incurred. Recoveries, which are recorded as revenue, are based on a formula that allows Atlanta Gas Light to recover operation and maintenance costs in excess of those included in its current base rates, depreciation expense and an allowed rate of return on capital expenditures. In the near term, the primary financial impact to Atlanta Gas Light from the

PRP is reduced cash flow from operating and investing activities, as the timing related to cost recovery does not match the timing of when costs are incurred. However, Atlanta Gas Light is allowed the recovery of carrying costs on the under-recovered balance resulting from the timing difference.

ENVIRONMENTAL REMEDIATION COSTS

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites.

Atlanta Gas Light

The presence of coal tar and certain other byproducts of a natural gas manufacturing process used to produce natural gas prior to the 1950s has been identified at or near 13 former operating sites in Georgia and Florida. Atlanta Gas Light has active environmental remediation or monitoring programs in effect at 10 sites. Two of three sites in Florida and one Georgia site are currently in the preliminary investigation or engineering design phase. The required soil remediation at our Georgia sites is scheduled to be completed by June 2005. As of December 31, 2004, Atlanta Gas Light's remediation program was approximately 78% complete.

Atlanta Gas Light has historically reported estimates of future remediation costs for these former sites based on probabilistic models of potential costs. These estimates are reported on an undiscounted basis. As cleanup options and plans mature and cleanup contracts are entered into, Atlanta Gas Light is increasingly able to provide conventional engineering estimates of the likely costs of many elements at its former sites. These estimates contain various engineering uncertainties, and Atlanta Gas Light continuously attempts to refine and update these engineering estimates.

Our current engineering estimate projects costs associated with Atlanta Gas Light's engineering estimates and in-place contracts to be $36 million. This is a reduction of $30 million from last year's estimate of projected engineering and in-place contracts, which resulted from $50 million of program expenditures incurred in the year ended September 30, 2004. During the same 12-month period Atlanta Gas Light realized increases in its future cost estimates totaling $20 million related to

- an increase in the contract value at its Augusta, Georgia site for treatment of two areas and additional deep excavation of contaminants
- the addition of harbor sediment removal at its St. Augustine, Florida site
- an increase at its Savannah, Georgia site for phase 2 excavation and a partially offsetting decrease in engineering and oversight costs
- an increase in the program management costs due to legal matters, environmental regulatory activities and oversight costs for the extension of work at the Savannah and Augusta sites

The engineering estimate was $66 million in 2003, which was a reduction of $43 million from the 2002 estimate. The decrease was a result of $37 million of program expenditures incurred in the year ended September 30, 2003 and a $6 million reduction in future cost estimates. For those remaining elements of Atlanta Gas Light's environmental remediation program where it is unable to perform engineering cost estimates at the current state of investigation, considerable variability remains in the estimates for future remediation costs. For these elements, the estimate for the remaining cost of future actions at these former operating sites is $14 million. Atlanta Gas Light estimates certain other costs related to administering the remediation program and remediation of sites currently in the investigation phase. Through January 2006, Atlanta Gas Light estimates the administrative costs to be $2 million.

For those sites currently in the investigation phase, Atlanta Gas Light's estimate for remediation is $9 million. This estimate is based on preliminary data received during 2004 with respect to the existence of contamination at those sites. Atlanta Gas Light's range of estimates for these sites is $4 million to $15 million. Atlanta Gas Light has accrued $9 million as this is its best estimate at this phase of the remediation process.

The liability does not include other potential expenses, such as unasserted property damage claims, personal injury or natural resource damage claims, unbudgeted legal expenses, or other costs for which Atlanta Gas Light may be held liable but with respect to which it cannot reasonably estimate the amount. The liability also does not include certain potential cost savings as described above. As of December 31, 2004, the remediation expenditures expected to be incurred over the next 12 months are reflected as a current liability of $27 million. Atlanta Gas Light's environmental remediation cost liability is composed of the following elements:

In millions	Dec 31, 2004	Dec 31, 2003	2004 vs. 2003
Projected engineering estimates and in-place contracts[1]	**$36**	$ 66	$(30)
Estimated future remediation costs[1]	**14**	15	(1)
Administrative expenses[2]	**2**	3	(1)
Other expenses[2]	**9**	10	(1)
Cash payments for cleanup expenditures[3]	**(5)**	(11)	6
Environmental remediation cost liability	**$56**	$ 83	$(27)

[1] As of September 30, 2004 and September 30, 2003.

[2] For the respective calendar years.

[3] Expenditures during the three months ended December 31, 2004 and December 31, 2003.

The environmental remediation cost liability is included in a corresponding regulatory asset, which is a combination of accrued environmental remediation costs and unrecovered cash expenditures for investigation and cleanup costs. Atlanta Gas Light has three ways of recovering investigation and cleanup costs. First, the Georgia Commission has approved an environmental remediation cost recovery rider. It allows recovery of the costs of investigation, testing, cleanup and litigation. Because of that rider, these actual and projected future costs related to investigation and cleanup to be recovered from customers in future years are included in our regulatory assets. The environmental remediation cost recovery mechanism allows for recovery of expenditures over a five-year period subsequent to the period in which the expenditures are incurred. Atlanta Gas Light expects to collect $27 million in revenues over the next 12 months under the environmental remediation cost recovery rider, which is reflected as a current asset. The amounts recovered from the recovery rider during the last three years were

- $25 million in 2004
- $23 million in 2003
- $17 million in 2002

The second way to recover costs is by exercising the legal rights Atlanta Gas Light believes it has to recover a share of its costs from other potentially responsible parties, typically former owners or operators of these sites. There were no material recoveries from potentially responsible parties during 2004, 2003 or 2002.

The third way to recover costs is from the receipt of net profits from the sale of remediated property. In June 2004, a residential and retail development located in Savannah, Georgia and adjacent to a former remediation site was sold, resulting in a gain of $6 million. All gains on sales of remediated property are required to be shared 70% with ratepayers through a reduction to the regulatory asset. Consequently, the unrecovered environmental remediation costs were reduced by approximately $4 million.

Elizabethtown Gas

In New Jersey, Elizabethtown Gas is currently conducting remedial activities with oversight from the New Jersey Department of Environmental Protection. Although the actual total cost of future environmental investigation and remediation efforts cannot be estimated with precision, the range of reasonably probable costs is from $30 million to $116 million. As of December 31, 2004, we recorded a liability of $30 million, as this is the best estimate at this phase of the remediation process.

Elizabethtown Gas' prudently incurred remediation costs for the New Jersey properties have been authorized by the NJBPU to be recoverable in rates through its Remediation Adjustment Clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $34 million, inclusive of interest, as of December 31, 2004, reflecting the future recovery of both incurred costs and future remediation liabilities in the state of New Jersey. Elizabethtown Gas has also been successful in recovering a portion of remediation costs incurred in New Jersey from its insurance carriers and continues to pursue additional recovery. As of December 31, 2004, the variation between the amounts of the environmental remediation cost liability recorded on the consolidated balance sheet and the associated regulatory asset results from expenditures for environmental investigation and remediation exceeding recoveries from ratepayers and insurance carriers.

Other

We also own a former NUI remediation site in Elizabeth City, North Carolina, which is subject to an order by the North Carolina Department of Energy and Natural Resources. We do not have precise estimates for the cost of investigating and remediating this site, although preliminary estimates for these costs range from $4 million to $16 million. As of December 31, 2004, we have recorded a liability of $4 million related to this site. There is another site in North Carolina where investigation and remediation is probable, although no regulatory order exists and we do not believe costs associated with this site can be reasonably estimated. In addition, there are as many as six other sites with which NUI had some association, although no basis for liability has been asserted. We do not believe that costs to investigate and remediate these sites, if any, can be reasonably estimated at this time.

With respect to these costs we are currently pursuing or intend to pursue recovery from ratepayers, former owners and operators and insurance carriers. Although we have been successful in recovering a portion of these remediation costs from our insurance carriers, we are not able to express a belief as to the success of additional recovery efforts. We are working with the regulatory agencies to prudently manage our remediation costs so as to mitigate the impact of such costs on both ratepayers and shareholders.

Note 6

EMPLOYEE BENEFIT PLANS

PENSION BENEFITS

We sponsor two defined benefit retirement plans (Retirement Plan) for our eligible employees, the AGL Resources Inc. Retirement Plan (AGL Retirement Plan) and NUI Corporation Retirement Plan (NUI Retirement Plan). A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant.

We generally calculate the benefits under the AGL Retirement Plan based on age, years of service and pay. The benefit formula for the Retirement Plan is a career average earnings formula for participants other than those participants who were employees as of July 1, 2000, and who were at least 50 years of age as of that date. We utilize a final average earnings benefit formula for participants who were both employees and over age 50 as of July 1, 2000, and will continue to utilize the final average earnings benefit formula for such participants until June 2010, at which time we will convert those Retirement Plan participants to a career average earnings formula.

NUI has a qualified noncontributing defined benefit retirement plan that covers substantially all its employees, other than Florida City Gas Company (Florida Gas) union employees, who participate in a union-sponsored multi-employer plan. Pension benefits are based on the number of years of credited service and on final average compensation.

Effective with our acquisition of NUI, we now administer the NUI Retirement Plan. Throughout 2005, we will maintain existing benefits for NUI employees, including participation in the NUI Retirement Plan. Beginning in 2006, eligible nonunion participants in the NUI Retirement Plan will become eligible to participate in the AGL Retirement Plan. Currently, participants of the NUI Retirement Plan have the option of receiving a lump sum distribution upon retirement, which is not permitted under the AGL Retirement Plan. However, the option to receive a lump sum payment will be provided for all benefits earned through December 31, 2005. The following tables present details about our pension plans:

In millions	AGL Retirement Plan Dec 31, 2004	Dec 31, 2003	NUI Retirement Plan Dec 31, 2004
Change in benefit obligation			
Benefit obligation at beginning of year	**$314**	$290	**$144**
Service cost	**5**	4	**—**
Interest cost	**19**	19	**1**
Actuarial loss	**21**	20	**—**
Benefits paid	**(19)**	(19)	**(1)**
Benefit obligation at end of year	**$340**	$314	**$144**
Change in plan assets			
Fair value of plan assets at beginning of year	**$259**	$208	**$108**
Actual return on plan assets	**26**	48	**4**
Employer contribution	**13**	22	**—**
Benefits paid	**(19)**	(19)	**(1)**
Fair value of plan assets at end of year	**$279**	$259	**$111**
Funded status			
Plan assets less benefit obligation at end of year	**$ (61)**	$ (55)	**$ (33)**
Unrecognized net loss	**108**	95	**—**
Unrecognized prior service benefit	**(11)**	(12)	**(3)**
Accrued pension cost	**$ 36**	$ 28	**$ (36)**
Amounts recognized in the statement of financial position consist of			
Prepaid benefit cost	**$ 43**	$ 34	**$ —**
Accrued benefit liability	**(7)**	(7)	**(36)**
Accumulated OCI	**(84)**	(66)	**—**
Net amount recognized at end of year	**$ (48)**	$ (39)	**$ (36)**

The accumulated benefit obligation (ABO) for our retirement plan and other information for our pension plans are indicated in the following tables:

In millions	AGL Retirement Plan Dec 31, 2004	AGL Retirement Plan Dec 31, 2003	NUI Retirement Plan Dec 31, 2004
Projected benefit obligation	**$340**	$314	**$144**
ABO	**327**	298	**118**
Fair value of plan assets	**279**	259	**111**
Increase (decrease) in minimum liability included in OCI	**18**	(14)	**—**
Components of net periodic benefit cost			
Service cost	**$ 5**	$ 4	**$ —**
Interest cost	**19**	19	**1**
Expected return on plan assets	**(23)**	(22)	**(1)**
Net amortization	**(1)**	(1)	**—**
Recognized actuarial (gain) loss	**5**	2	**—**
Net annual pension cost	**$ 5**	$ 2	**$ —**

The following table indicates our weighted average assumptions used to determine benefit obligations at the balance sheet date:

	AGL Retirement Plan Dec 31, 2004	AGL Retirement Plan Dec 31, 2003	NUI Retirement Plan Dec 31, 2004
Discount rate	**5.8%**	6.3%	**5.8%**
Rate of compensation increase	**4.0%**	4.5%	**4.0%**

We consider a number of factors in the determination and selection of our assumptions of the overall expected long-term rate of return on plan assets. We consider the historical long-term return experience of our assets, the current and expected allocation of our plan assets as well as expected long-term rates of return. We derive these expected long-term rates of return with the assistance of our investment advisors and generally base these rates on a 10-year horizon for various asset classes, our expected investments of plan assets and active asset management as opposed to investment in a passive index fund. We base our expected allocation of plan assets on a diversified portfolio consisting of domestic and international equity securities, fixed income, real estate, private equity securities and alternative asset classes.

As of December 1, 2004, the discount rate used to determine NUI's opening balance sheet benefit obligation was 5.8%. This discount rate was also utilized to determine net periodic benefit cost for the month of December 2004. The following table presents the weighted average assumptions used to determine net periodic benefit cost at the beginning of the period, which was January 1, for the AGL Retirement Plan.

	AGL Retirement Plan Dec 31, 2004	AGL Retirement Plan Dec 31, 2003	NUI Retirement Plan Dec 31, 2004
Discount rate	**6.3%**	6.8%	**5.8%**
Expected return on plan assets	**8.8%**	8.8%	**8.5%**
Rate of compensation increase	**4.0%**	4.5%	**4.0%**

Our Retirement Plan's weighted average asset allocations at December 31, 2004 and 2003 and our target asset allocation ranges are as follows:

	Target Range Allocation of Assets	Actual Allocation on a Weighted Average Basis: AGL Retirement Plan 2004	AGL Retirement Plan 2003	NUI Retirement Plan 2004
Equity	40%–85%	**71%**	67%	**72%**
Fixed income	25%–50%	**25**	30	**28**
Real estate and other	0%–10%	**3**	—	**—**
Cash	0%–10%	**1**	3	**—**

The Retirement Plan Investment Committee (the Committee) is appointed by our Board of Directors and is responsible for overseeing the investments of the Retirement Plan. Further, we have an Investment Policy (the Policy) for the Retirement Plan, which has a goal to preserve the Retirement Plan's capital and maximize investment earnings in excess of inflation within acceptable levels of capital market volatility. To accomplish this goal, the Retirement Plan assets are actively managed with the objective of optimizing long-term return while maintaining a high standard of portfolio quality and proper diversification.

The Policy's risk management strategy establishes a maximum tolerance for risk in terms of volatility to be measured at 75% of the volatility experienced by the S&P 500. We will continue to more broadly diversify the Retirement Plan to minimize the risk of large losses in a single asset class. The Policy's permissible investments include domestic and international equities (including convertible securities and mutual funds), domestic and international fixed income (corporate and U.S. government obligations), cash and cash equivalents and other suitable investments. The asset mix of these permissible investments is maintained within the Policy's target allocations as included in the table above, but the Committee can establish different allocations between various classes and/or investment managers in order to better achieve expected investment results.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded ABO, as the primary factors that drive the value of our unfunded ABO are the assumed discount rate and the actual return on plan assets. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes the differences between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year moving weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year moving weighted average methodology, which affects the expected return on plan assets component of pension expense.

Our employees do not contribute to the Retirement Plan. We fund the plan by contributing at least the minimum amount required by applicable regulations and as recommended by our actuary. We calculate the amount of funding using an actuarial method called the projected unit credit cost method. However, we may also fund the Retirement Plan in excess of the minimum required amount. We expect to make a $1 million contribution to the pension plans in 2005.

POSTRETIREMENT BENEFITS

We sponsor two defined benefit postretirement health care plans for our eligible employees, the AGL Resources Inc. Postretirement Health Care Plan (AGL Postretirement Plan) and the NUI Corporation Postretirement Health Care Plan (NUI Postretirement Plan). Eligibility for these benefits is based on age and years of service.

The NUI Postretirement Plan provides certain medical and dental health care benefits to retirees, other than retirees of Florida City Gas Company, depending on their age, years of service and start date. The health care plans are contributory and NUI funded a portion of these future benefits through a Voluntary Employees' Beneficiary Association. Effective July 2000, NUI no longer offers postretirement benefits other than pensions for any new hires. In addition, NUI capped its share of costs at $500 per participant, per month for retirees under age 65, and at $150 per participant, per month for retirees over age 65. Effective with our acquisition of NUI, we acquired the NUI Postretirement Plan. Beginning in 2006, eligible participants in the NUI Postretirement Plan will become eligible to participate in the AGL Postretirement Plan.

The AGL Postretirement Plan covers all eligible AGL Resources employees who were employed as of June 30, 2002, if they reach retirement age while working for us. In addition, the state regulatory commissions have approved phase-ins that defer a portion of other postretirement benefits expense for future recovery. We recorded a regulatory asset of $14 million as of December 31, 2004 and $9 million as of December 31, 2003. In addition, we recorded a regulatory liability of $2 million as of December 31, 2004 and $2 million as of December 31, 2003.

Effective December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Prescription Drug Act) was signed into law. This act provides for a prescription drug benefit under Medicare (Part D) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D.

Effective July 2004, the AGL Postretirement Plan was amended to remove prescription drug coverage for Medicare-eligible retirees, effective January 1, 2006. Certain grandfathered NUI retirees participating in the NUI Postretirement Plan will continue receiving a prescription drug benefit for some period of time.

The AGL Postretirement Plan's accumulated postretirement benefit obligation decreased by approximately $24 million and net annual cost decreased by $2 million due to the elimination of prescription drug coverage for Medicare-eligible retirees. The 2004 net periodic postretirement benefit cost reflects both the plan amendment to remove prescription drug coverage under the AGL Postretirement Plan, described above, and the federal subsidy for NUI grandfathered retirees. The following tables present details about our postretirement benefits:

In millions	AGL Postretirement Plan Dec 31, 2004	AGL Postretirement Plan Dec 31, 2003	NUI Postretirement Plan Dec 31, 2004
Change in benefit obligation			
Benefit obligation at beginning of year	$134	$129	$ 23
Service cost	1	1	—
Interest cost	7	8	—
Plan amendments	(24)	—	—
Actuarial loss	(12)	6	—
Benefits paid	(8)	(10)	—
Benefit obligation at end of year	$ 98	$134	$ 23
Change in plan assets			
Fair value of plan assets at beginning of year	$ 44	$ 38	$ 9
Actual return on plan assets	5	8	—
Employer contribution	8	8	—
Benefits paid	(8)	(10)	—
Fair value of plan assets at end of year	$ 49	$ 44	$ 9
Funded status			
ABO in excess of plan assets	$ (49)	$ (90)	$(14)
Unrecognized loss	30	44	—
Unrecognized transition amount	1	1	—
Unrecognized prior service cost (benefit)	(26)	(6)	—
Accrued benefit cost	$ (44)	$ (51)	$(14)
Amounts recognized in the statement of financial position consist of			
Prepaid benefit cost	$ —	$ —	$ —
Accrued benefit liability	(44)	(51)	(14)
Accumulated OCI	—	—	—
Net amount recognized at end of year	$ (44)	$ (51)	$(14)

The following table presents details on the components of our net periodic benefit costs at the balance sheet data:

In millions	AGL Postretirement Plan 2004	AGL Postretirement Plan 2003	NUI Postretirement Plan 2004
Service cost	$ 1	$ 1	$—
Interest cost	7	8	—
Expected return on plan assets	(3)	(3)	—
Amortization of transition amount	(2)	—	—
Amortization of regulatory asset	1	2	—
Net periodic postretirement benefit cost	$ 4	$ 8	$—

The following table presents our weighted average assumptions used to determine benefit obligations at the beginning of the period, which was January 1 for the AGL Postretirement Plan and December 1 for the NUI Postretirement Plan:

	AGL Postretirement Plan 2004	AGL Postretirement Plan 2003	NUI Postretirement Plan 2004
Discount rate	5.8%	6.3%	5.8%

The following table presents our weighted average assumptions used to determine net periodic benefit cost:

	AGL Postretirement Plan 2004	AGL Postretirement Plan 2003	NUI Postretirement Plan 2004
Discount rate	6.3%	6.8%	5.8%
Expected return on plan assets	8.8%	8.8%	2.0%
Rate of compensation increase	4.0%	4.5%	—

We consider the same factors in the determination and selection of our assumptions of the overall expected long-term rate of return on plan assets as those considered in the determination and selection of the overall expected long-term rate of return on plan assets for our Retirement Plan. For purposes of measuring our accumulated postretirement benefit obligation, the assumed pre-Medicare and post-Medicare health care inflation rates are as follows:

Assumed Health Care Cost Trend Rates at December 31,	AGL Postretirement Plan Pre-Medicare Cost (pre-65 years old) 2004	2003	Post-Medicare Cost (post-65 years old) 2004	2003
Health care costs trend assumed for next year	**11.3%**	10.0%	**11.3%**	12.0%
Rate to which the cost trend rate gradually declines	**2.5%**	5.0%	**2.5%**	5.0%
Year that the rate reaches the ultimate trend rate	**2006**	2010	**2006**	2011

Assumed Health Care Cost Trend Rates at December 31,	NUI Postretirement Plan 2004
Health care costs trend assumed for next year	**9.0%**
Rate to which the cost trend rate gradually declines	**5.0%**
Year that the rate reaches the ultimate trend rate	**2008**

Assumed health care cost trend rates have a significant effect on the amounts reported for our health care plans. A one-percentage-point change in the assumed health care cost trend rates would have the following effects:

In millions	One-percentage-point Increase	Decrease
Effect on total of service and interest cost[1]	$1	$(1)
Effect on accumulated postretirement benefit obligation[1]	6	(6)

[1] There were no material amounts for the NUI Postretirement benefit obligation or interest costs.

The following table presents expected benefit payments covering the periods 2005 through 2014 for our qualified pension plans and postretirement health care plans. There will be benefit payments under these plans beyond 2014.

For the year ended Dec 31, In millions	AGL Resources' Plans Pension Plan	Postretirement Health Care Plans	NUI's Plans Pension Plan	Postretirement Health Care Plans
2005	$ 19	$ 8	$17	$2
2006	18	7	8	2
2007	18	7	8	2
2008	18	7	9	2
2009	19	7	9	2
2010–2014	101	34	61	9

Our investment policies and strategies, including target allocation ranges, are similar to those of our Retirement Plan. We fund the plan annually, and retirees contribute 20% of medical premiums, 50% of the medical premium for spousal coverage and 100% of the dental premium. Our postretirement benefit plan's weighted average asset allocations for 2004, 2003 and 2002 and our target asset allocation ranges are as follows:

	Target Asset Allocation Ranges	2004	2003
Equity	40%–85%	**67%**	59%
Fixed income	25%–50%	**32%**	40%
Real estate and other	0%–10%	**–%**	–%
Cash	0%–10%	**1%**	1%

EMPLOYEE SAVINGS PLAN BENEFITS

We sponsor the Retirement Savings Plus Plan (RSP), a defined contribution benefit plan that allows eligible participants to make contributions up to specified limits to its account. Under the RSP, we made matching contributions to participant accounts in the following amounts:

- $5 million in 2004
- $4 million in 2003
- $4 million in 2002

We also sponsor the Nonqualified Savings Plan (NSP), an unfunded, nonqualified plan similar to the RSP. The NSP provides an opportunity for eligible employees who could reach the maximum contribution amount in the RSP, to contribute additional amounts for retirement savings. Our contributions to the NSP were not significant.

Effective December 1, 2004, all NUI employees who were participating in NUI's qualified defined contribution benefit plan were eligible to participate in the RSP, and those who were participants in NUI's nonqualified defined contribution plan became eligible to participate in the NSP.

Note 7

STOCK-BASED COMPENSATION PLANS

EMPLOYEE STOCK-BASED COMPENSATION PLANS AND AGREEMENTS

We currently sponsor the following stock-based compensation plans:

- The Long-Term Incentive Plan (LTIP) provides for grants of performance units, restricted stock and incentive and nonqualified stock options to key employees. The LTIP currently authorizes the issuance of up to 7.9 million shares of our common stock.
- A predecessor plan, the Long-Term Stock Incentive Plan (LTSIP), provides for grants of restricted stock, incentive and nonqualified stock options and stock appreciation rights (SARs) to key employees. Following shareholder approval of the LTIP, no further grants have been made under the LTSIP.
- The Officer Incentive Plan (Officer Plan) provides for grants of nonqualified stock options and restricted stock to new-hire officers. The Officer Plan authorizes the issuance of up to 600,000 shares of our common stock.
- SARs have been granted to key employees under individual agreements that permit the holder to receive cash in an amount equal to the difference between the fair market value of a share of our common stock on the date of exercise and the SAR base value. A total of 26,863 SARs currently are outstanding.
- We amended the Non-Employee Directors Equity Compensation Plan (Directors Plan), in which all nonemployee directors participate, to eliminate the granting of stock options effective December 2002. As a result, the Directors Plan now provides solely for the issuance of restricted stock. It currently authorizes the issuance of up to 200,000 shares of our common stock.

The following table summarizes activity for key employees and nonemployee directors related to grants of stock options:

	Number of Options	Weighted Average Exercise Price
Outstanding – December 31, 2001	3,587,501	$20.06
Granted	988,564	21.49
Exercised	(785,853)	19.28
Forfeited	(156,255)	21.59
Outstanding – December 31, 2002	3,633,957	$20.55
Granted	939,262	26.76
Exercised	(863,112)	20.08
Forfeited	(199,137)	22.00
Outstanding – December 31, 2003	3,510,970	$22.25
Granted	**103,900**	**29.72**
Exercised	**(1,050,053)**	**20.90**
Forfeited	**(390,745)**	**22.44**
Outstanding – December 31, 2004	**2,174,072**	**$23.23**

Information about outstanding and exercisable options as of December 31, 2004 is as follows:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
$13.75 to $17.49	2,199	5.0	$16.99	2,199	$16.99
$17.50 to $19.99	201,640	3.8	$18.85	199,973	$18.84
$20.00 to $24.10	1,164,156	5.5	$21.23	1,126,827	$21.17
$24.11 to $30.00	751,936	8.4	$26.97	325,737	$26.91
$30.01 to $34.00	54,141	6.2	$31.07	3,524	$31.20
Outstanding – December 31, 2004	**2,174,072**	**6.4**	**$23.23**	**1,658,260**	**$22.04**

Summarized below are outstanding options that are fully exercisable:

	Number of Options	Weighted Average Exercise Price
Exercisable — December 31, 2002	2,483,756	$20.07
Exercisable — December 31, 2003	2,154,877	$20.47
Exercisable — December 31, 2004	**1,658,260**	**$22.04**

Our stock-based employee compensation plans are accounted for under the recognition and measurement principles of APB 25 and related interpretations. For our stock option plans, we generally do not reflect stock-based employee compensation cost in net income, as options for those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. For our stock appreciation rights, we reflect stock-based employee compensation cost based on the fair value of our common stock at the balance sheet date since these awards constitute a variable plan under APB 25.

In accordance with the fair value method of determining compensation expense, we utilized the Black-Scholes pricing model and the estimate below for the years ended December 31, 2004, 2003 and 2002:

	2004	2003	2002
Expected life (years)	**7**	7	7
Interest rate	**3.7%**	3.8%	4.6%
Volatility	**16.9%**	19.2%	19.2%
Dividend yield	**3.9%**	4.2%	5.0%
Fair value of options granted	**$3.72**	$3.75	$2.92

Participants realize value from option grants or SARs only to the extent that the fair market value of our common stock on the date of exercise of the option or SAR exceeds the fair market value of the common stock on the date of the grant. The compensation costs that have been charged against income for performance units, restricted stock and other stock-based awards were $7 million in 2004, $8 million in 2003 and $2 million in 2002.

INCENTIVE AND NONQUALIFIED STOCK OPTIONS

We grant incentive and nonqualified stock options at the fair market value on the date of the grant. The vesting of incentive options is subject to a statutory limitation of $100,000 per year under Section 422A of the Internal Revenue Code. Otherwise, nonqualified options generally become fully exercisable not earlier than six months after the date of grant and generally expire 10 years after that date.

PERFORMANCE UNITS

In general, a performance unit is an award to receive an equal number of shares of company common stock or an equivalent value of cash subject to the achievement of certain pre-established performance criteria.

In February 2002, we granted to a select group of executives a total of 1.5 million in performance units with a performance measurement period that ended December 31, 2004. The amount actually earned would be based on the highest average closing price of our common stock over any 10 consecutive trading days during the performance measurement period and could range from a minimum of 10% to 100% of the granted units. The performance units were subject to certain transfer restrictions and forfeiture upon termination of employment. In addition, during a portion of the performance measurement period, performance units were eligible for dividend credits based on vested performance units. Of the 1.5 million units that were granted, only 1 million units were eligible for vesting at December 31, 2004. Upon vesting, the performance units were payable in shares of our common stock, provided, however, at the election of the participant, up to 50% was payable in cash.

At December 31, 2004, based on the highest average closing price over any 10 consecutive trading days during the performance measurement period, only 18.31% of units were vested, representing an aggregate of 198,000 units, including accrued dividends. These units were valued at our closing stock price on December 31, 2004 of $33.24 per unit representing a value of $6.6 million. The total value of the awards in the amount of $6.6 million was paid out as follows:

- $2.6 million paid in cash
- $2.8 million withheld to cover applicable taxes
- 35,342 shares of common stock with an approximate value of $1.2 million

In November 1999, we granted performance units that vested in September 2002. Based on performance achievement and the accrual of dividend credit, a total of 10,254 shares of common stock were issued to the participants. We did not grant performance units in 2004 or 2003.

STOCK APPRECIATION RIGHTS

We grant SARs, which are payable in cash, at fair market value on the date of grant. SARs generally become fully exercisable not earlier than 12 months after the date of grant and generally expire six years after that date. We recognize the intrinsic value of the SARs as compensation expense over the vesting period. Compensation expense for 2004 and 2003 was immaterial. The following table summarizes activity related to grants of SARs:

	Number of SARs	Weighted Average Exercise Price
Outstanding as of December 31, 2002	141,253	$23.50
Issued	45,790	$24.30
Exercised	(17,718)	23.50
Forfeited	(9,368)	23.99
Outstanding as of December 31, 2003	159,957	$23.70
Issued	**—**	**$ —**
Exercised	**(60,262)**	**23.70**
Forfeited	**(72,832)**	**23.50**
Outstanding as of December 31, 2004	**26,863**	**$24.24**

DIRECTORS PLAN

Under the Directors Plan, each nonemployee director receives an annual retainer that has an aggregate value of $60,000. At the election of each director, the annual retainer is paid in cash (with a $30,000 limit) and/or shares of our common stock or is deferred and invested in common stock equivalents under the 1998 Common Stock Equivalent Plan for Non-Employee Directors. Upon initial election to our Board of Directors, each nonemployee director receives 1,000 shares of common stock on the first day of service.

RESTRICTED STOCK AWARDS

Restricted stock awards generally are subject to some vesting restrictions. We awarded restricted stock, net of forfeitures, to key employees and nonemployee directors in the following amounts:

	2004	2003	2002
Employees	**51,300**	244,128	30,000
Nonemployee directors	**8,727**	12,152	1,410
Total	**60,027**	256,280	31,410
Weighted average fair value at year end	**$32.45**	$27.15	$23.19

In addition, 104,000 of the 256,280 shares awarded to selected employees in 2003 vested in 2004. The remaining nonvested shares were contingent upon our achievement of selected cash flow performance measures over the one-year performance measurement period. Recipients were entitled to vote and receive dividends on stock awards. The shares were subject to certain transfer restrictions and are forfeited upon termination of employment, absent a change of control.

EMPLOYEE STOCK PURCHASE PLAN

We have established the Employee Stock Purchase Plan (ESPP), a nonqualified employee stock purchase plan for eligible employees. Under the ESPP, employees may purchase shares of our common stock during quarterly intervals at 85% of fair market value. Employee contributions under the ESPP may not exceed $25,000 per employee during any calendar year. The ESPP currently allows for the purchase of 600,000 shares. As of December 31, 2004, our employees have purchased 73,254 shares leaving 526,746 shares available for purchase. The ESPP was adopted by our Board in 2001, with an initial term of four years that expired January 31, 2005. Our Board of Directors approved an amendment to the ESPP, subject to shareholder approval at the next annual meeting of shareholders, to extend the term of the ESPP for a 10-year period effective January 31, 2005. More information about the ESPP is presented below:

	2004	2003	2002
Shares purchased on the open market	**35,789**	24,871	12,594
Average per share purchase price	**$ 25.20**	$ 22.08	$ 23.22
Purchase price discount paid	**$159,144**	$97,400	$44,024

Note 8
FINANCING

Dollars in millions	Year(s) Due	Interest Rate as of Dec 31, 2004	Outstanding as of: Dec 31, 2004	Dec 31, 2003
Short-term debt				
Commercial paper[1]	2005	2.5%	$ 314	$ 303
Current portion of long-term debt	—	—	—	77
Sequent line of credit[2]	2005	2.5	18	3
Current portion of capital leases	2005	4.9	2	—
Total short-term debt[3]		2.5%	$ 334	$ 383
Long-term debt — net of current portion				
Medium-Term notes				
Series A	2021	9.1%	$ 30	$ 30
Series B	2012–2022	8.3–8.7	61	61
Series C	2014–2027	6.6–7.3	117	122
Senior notes	2011–2013	4.5–7.1	975	525
Gas facility revenue bonds, net of unamortized issuance costs	2022–2033	1.9–6.4	199	—
Notes payable to Trusts	2037–2041	8.0–8.2	232	—
Trust Preferred Securities	2037–2041	—	—	222
Capital leases	2013	4.9	8	—
AGL Capital interest rate swaps	2011–2041	3.6–5.2	1	(4)
Total long-term debt[3]		6.0%	$1,623	$ 956
Total short-term and long-term debt[3]		5.4%	$1,957	$1,339

[1] The daily weighted average rate was 1.6% for 2004 and 1.3% for 2003.

[2] The daily weighted average rate was 2.0% for 2004 and 1.6% for 2003.

[3] The weighted average interest rate excludes capital leases but includes interest rate swaps, if applicable.

SHORT-TERM DEBT

Our short-term debt at December 31, 2004 and 2003 was composed of borrowings under our commercial paper program, which consisted of short-term, unsecured promissory notes with maturities ranging from 3 to 56 days, Atlanta Gas Light's Medium-Term notes with maturities within one year, current portions of our capital lease obligations, Sequent's line of credit and SouthStar's line of credit.

Commercial Paper

In September 2004, we amended our credit facility that supports our commercial paper program (Credit Facility). Under the terms of the amendment, the Credit Facility has been extended from May 26, 2007 to September 30, 2009. The aggregate principal amount available under the Credit Facility has been increased from $500 million to $750 million and the cost of borrowing has been decreased relative to the prior credit agreements. In addition, our option to increase the aggregate cumulative principal amount available for borrowing on not more than one occasion during each calendar year during the term of the Credit Facility has been increased from $200 million to $250 million.

Sequent Line of Credit

In June 2004, Sequent's $25 million unsecured line of credit was extended to July 2005. This unsecured line of credit is used solely for the posting of exchange deposits and is unconditionally guaranteed by us. This line of credit bears interest at the federal funds effective rate plus 0.5%.

SouthStar Line of Credit

In April 2004, SouthStar amended its $75 million revolving line of credit, which is used to meet seasonal working capital needs. SouthStar's line of credit is scheduled to expire in April 2007 and is not guaranteed by us. At December 31, 2004, there were no amounts outstanding under this facility.

LONG-TERM DEBT

Our long-term debt matures more than one year from the date of issuance and consists of Medium-Term notes Series A, Series B and Series C, which we issued under an indenture dated December 1, 1989, Senior Notes, Gas Facility Revenue Bonds, notes payable to Trusts and capital leases. The notes are unsecured and rank on parity with all our other unsecured indebtedness. Our annual maturities of long-term debt are as follows:

- no maturities in 2005–2010
- $1,623 million in 2011 and beyond

Senior Notes

In February 2001, we issued $300 million of Senior Notes with a maturity date of January 14, 2011. These Senior Notes have an interest rate of 7.125% payable on January 14 and July 14, beginning July 14, 2001. The proceeds from the issuance were used to refinance a portion of the existing short-term debt under the commercial paper program.

In March 2003, we entered into interest rate swaps of $100 million to effectively convert a portion of the fixed-rate interest obligation on the $300 million in Senior Notes Due 2011 to a variable-rate obligation. We pay floating interest each January 14 and July 14 at six-month LIBOR plus 3.4%. The effective variable interest rate at December 31, 2004 was 5.2%. These interest rate swaps expire January 14, 2011, unless terminated earlier. For more information on our interest rate swaps, see Note 4.

In July 2003, we issued $225 million in Senior Notes with a maturity date of April 15, 2013. The Senior Notes have an interest rate of 4.45% payable on April 15 and October 15 of each year, beginning October 15, 2003 with interest accruing from July 2, 2003. We used the net proceeds from the Senior Notes to repay approximately $204 million of Medium-Term notes as well as approximately $20 million of short-term debt.

In September 2004, we issued $250 million in Senior Notes with a maturity of October 1, 2034. The Senior Notes have an interest rate of 6.00% payable on April 1 and October 1 of each year, beginning April 1, 2005 with interest accruing from September 27, 2004.

In December 2004, we issued $200 million in Senior Notes with a maturity of January 15, 2015. The Senior Notes have an interest rate of 4.95% payable on January 15 and July 15 of each year, beginning July 15, 2005 with interest accruing from December 20, 2004. We used the net proceeds from both of the senior notes issuances in 2004 to repay commercial paper borrowings and for general corporate purposes.

The trustee with respect to all of the above-referenced senior notes is the Bank of New York Trust Company, N.A., pursuant to an indenture dated February 20, 2001. We fully and unconditionally guarantee all our senior notes.

Gas Facility Revenue Bonds

NUI Utilities, Inc., a wholly owned subsidiary of NUI, had outstanding at closing $200 million of indebtedness pursuant to Gas Facility Revenue Bonds. We do not guarantee or provide any other form of security for the repayment of this indebtedness. NUI Utilities is party to a series of loan agreements with the New Jersey Economic Development Authority (NJEDA) pursuant to which the NJEDA has issued four series of Gas Facility Revenue Bonds:

- $46 million of bonds at 6.35%, due October 1, 2022
- $20 million of bonds at 6.4%, due October 1, 2024
- $39 million of bonds at variable rates, due June 1, 2026 (Variable Bonds)
- $55 million of bonds at 5.7%, due June 1, 2032
- $40 million of bonds at 5.25%, due November 1, 2033

The Variable Bonds contain a provision whereby the holder can "put" the bonds back to the issuer. In 1996, NUI Utilities executed a long-term Standby Bond Purchase Agreement (SBPA) with a syndicate of banks, which was amended and restated on June 12, 2001. Under the terms of the SBPA, as further amended, The Bank of New York Trust Company, N.A. (Bank of New York) is obligated under certain circumstances to purchase Variable Bonds that are tendered by the holders thereof and not remarketed by the remarketing agent. Such obligation of the Bank of New York would remain in effect until the expiration of the SBPA, unless it is extended or earlier terminated.

The terms of the SBPA restrict the payment of dividends by NUI Utilities to an amount based, in part, on the earned surplus of NUI Utilities. On May 19, 2004, NUI Utilities and the Bank of New York amended the SBPA to eliminate the effect of NUI Utilities' settlement with the NJBPU and the estimated refunds to customers in Florida on the earned surplus of NUI Utilities. In addition, the amendment extended the expiration date of the SBPA to June 29, 2005.

If the SBPA is not further extended beyond June 29, 2005, in accordance with the terms of the Variable Bonds, all the Variable Bonds would be subject to mandatory tender at a purchase price of 100% of the principal amount, plus accrued interest, to the date of tender. In such case, any Variable Bonds that are not remarketable by the remarketing agent will be purchased by the Bank of New York.

Beginning six months after the expiration or termination of the SBPA, any Variable Bonds still held by the bank must be redeemed or purchased by NUI Utilities in 10 equal, semi-annual installments. In addition, while the SBPA is in effect, any tendered Variable Bonds that are purchased by the bank and not remarketed within one year must be redeemed or purchased by NUI Utilities at such time, and every six months thereafter, in 10 equal, semi-annual installments.

As of December 31, 2004, the aggregate principal and accrued interest on the outstanding Variable Bonds totaled approximately $39 million. Principal and any unpaid interest on the outstanding Variable Bonds are due on June 1, 2026, unless the put option is exercised before that time.

Notes Payable to Trusts

In June 1997, we established AGL Capital Trust I (Trust I), a Delaware business trust, of which AGL Resources owns all the common voting securities. Trust I issued and sold $75 million of 8.17% capital securities (liquidation amount $1,000 per capital security) to certain initial investors. Trust I used the proceeds to purchase 8.17% Junior Subordinated Deferrable Interest Debentures issued by us. Trust I capital securities are subject to mandatory redemption at the time of the repayment of the junior subordinated debentures on June 1, 2037, or the optional prepayment by us after May 31, 2007.

In March 2001, we established AGL Capital Trust II (Trust II), a Delaware business trust, of which AGL Capital owns all the common voting securities. In May 2001, Trust II issued and sold $150 million of 8.00% capital securities (liquidation amount $25 per capital security). Trust II used the proceeds to purchase 8.00% Junior Subordinated Deferrable Interest Debentures issued by us. The proceeds from the issuance were used to refinance a portion of our existing short-term debt under the commercial paper program. Trust II capital securities are subject to mandatory redemption at the time of the repayment of the junior subordinated debentures on May 15, 2041, or the optional prepayment by AGL Capital after May 21, 2006. Additionally we entered into interest rate swaps to effectively convert a portion of the fixed-rate interest obligation on our notes payable to Trusts to a variable-rate obligation. The effective variable interest rate at December 31, 2004 was 3.6%. For more information on our interest rate swaps, see Note 4.

The trustee is the Bank of New York with respect to the 8.17% capital securities pursuant to an indenture dated June 11, 1997, and with respect to the 8.00% capital securities pursuant to an indenture dated May 21, 2001. We fully and unconditionally guarantee all our Trusts' obligations for the capital securities.

Other Preferred Securities

As of December 31, 2003, we had 10.0 million shares of authorized, unissued Class A Junior Participating Preferred Stock, no par value, and 10.0 million shares of authorized, unissued preferred stock, no par value.

Capital Leases

Our capital leases consist primarily of a sale/leaseback transaction completed in 2002 by Florida Gas related to its gas meters and other equipment and will be repaid over 11 years. Pursuant to the terms of the lease agreement, Florida Gas is required to insure the leased equipment during the lease term. In addition, at the expiration of the lease term, Florida Gas has the option to purchase the leased meters from the lessor at their fair market value.

DEFAULT EVENTS

Our Credit Facility financial covenants and the PUHCA require us to maintain a ratio of total debt to total capitalization of no greater than 70%. Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include

- a maximum leverage ratio
- minimum net worth
- insolvency events and nonpayment of scheduled principal or interest payments
- acceleration of other financial obligations
- change of control provisions

We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that requires us to issue equity based on credit ratings or other trigger events. We are currently in compliance with all existing debt provisions and covenants.

Note 9

COMMON SHAREHOLDERS' EQUITY

SHAREHOLDER RIGHTS PLAN

On March 6, 1996, our Board of Directors adopted a Shareholder Rights Plan. The plan contains provisions to protect our shareholders in the event of unsolicited offers to acquire us or other takeover bids and practices that could impair the ability of the Board of Directors to represent shareholders' interests fully. As required by the Shareholder Rights Plan, the Board of Directors declared a dividend of one preferred share purchase right (a Right) for each outstanding share of our common stock, with distribution made to shareholders of record on March 22, 1996.

The Rights, which will expire March 6, 2006, are represented by and traded with our common stock. The Rights are not currently exercisable and do not become exercisable unless a triggering event occurs. One of the triggering events is the acquisition of 10% or more of our common stock by a person or group of affiliated or associated persons. Unless previously redeemed, upon the occurrence of one of the specified triggering events, each Right will entitle its holder to purchase one one-hundredth of a share of Class A Junior Participating Preferred Stock at a purchase price of $60. Each preferred share will have 100 votes, voting together with the common stock. Because of the nature of the preferred shares' dividend, liquidation and voting rights, one one-hundredth of a share of preferred stock is intended to have the value, rights and preferences of one share of common stock. As of December 31, 2004, 1.0 million shares of Class A Junior Participating Preferred Stock were reserved for issuance under that plan.

EQUITY OFFERING

On November 18, 2004, we completed our public offering of 11.04 million shares of common stock. We priced the offering at $31.01 per share and generated net proceeds of approximately $332 million, which we used to purchase the outstanding capital stock of NUI and to repay short-term debt incurred to fund the purchase of Jefferson Island. In February 2003, we completed our public offering of 6.4 million shares of common stock. The offering generated net proceeds of approximately $137 million, which we used to repay outstanding short-term debt and for general corporate purposes.

DIVIDENDS

Our common shareholders may receive dividends when declared by our Board of Directors, which may be paid in cash, stock or other form of payment. In certain cases, our ability to pay dividends to our common shareholders is limited by the following:

- satisfying our obligations under certain financing agreements, including debt-to-capitalization and total shareholders' equity covenants
- satisfying our obligations to any preferred shareholders
- restrictions under the PUHCA on our payment of dividends out of capital or unearned surplus without prior permission from the SEC

Under Georgia law, the payment of dividends to the holders of our common stock is limited to our legally available assets and subject to the prior payment of dividends on any outstanding shares of preferred stock and junior preferred stock. Our assets are not legally available for paying dividends if

- we could not pay our debts as they become due in the usual course of business
- our total assets would be less than our total liabilities plus, subject to some exceptions, any amounts necessary to satisfy the preferential rights upon dissolution of shareholders whose preferential rights are superior to those of shareholders receiving the dividends

We announced the following increases in our cash dividends payable on our common stock:

- In February 2005, we announced a 7% increase in our common stock dividend. The increase raised the quarterly dividend from $0.29 per share to $0.31 per share, for an indicated annual dividend of $1.24 per share.
- In April 2004, we announced a 4% increase in our common stock dividend, raising the quarterly dividend from $0.28 per share to $0.29 per share which indicated an annual dividend of $1.16 per share.
- In April 2003, we announced a 4% increase in our common stock dividend from $0.27 per share to $0.28 per share, which indicated an annual dividend of $1.12.

Note 10

COMMITMENTS AND CONTINGENCIES

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

We have incurred various contractual obligations and financial commitments in the normal course of our operations and financing activities. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. We calculate any expected pension contributions using an actuarial method called the projected unit credit cost method, and pursuant to these calculations, we expect to make a $1 million pension contribution in 2005. The following table illustrates our expected future contractual cash obligations as of December 31, 2004:

		Payments Due Before December 31,			
In millions	Total	2005	2006 & 2007	2008 & 2009	2010 & Thereafter
Long-term debt[1,2]	$1,623	$ —	$ 2	$ 2	$1,619
Pipeline charges, storage capacity and gas supply[3,4]	1,051	258	262	179	352
Short-term debt[2]	334	334	—	—	—
PRP costs[5]	327	85	162	80	—
Operating leases[6]	170	27	39	29	75
ERC[5]	90	27	10	12	41
Commodity and transportation charges	20	19	1	—	—
Total	$3,615	$750	$476	$302	$2,087

[1] Includes $232 million of notes payable to Trusts redeemable in 2006 and 2007.

[2] Does not include the interest expense associated with the long-term and short-term debt.

[3] Charges recoverable through a PGA mechanism or alternatively billed to Marketers. Also includes demand charges associated with Sequent.

[4] A subsidiary of NUI entered into two 20-year agreements for the firm transportation and storage of natural gas during 2003 with the annual demand charges aggregate of approximately $5 million. As a result of our acquisition of NUI and in accordance with SFAS 141, the contracts were valued at fair value. The $38 million currently allocated to accrued pipeline demand charges on our consolidated balance sheets represent our estimate of the fair value of the acquired contracts. The liability will be amortized over the remaining life of the contracts.

[5] Charges recoverable through rate rider mechanisms.

[6] We have certain operating leases with provisions for step rent or escalation payments, or certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms in accordance with SFAS No. 13, "Accounting for Leases." However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein.

SouthStar has natural gas purchase commitments related to the supply of minimum natural gas volumes to its customers. These commitments are priced on an index plus premium basis. At December 31, 2004, SouthStar had obligations under these arrangements for 11.2 Bcf for the year ending December 31, 2005. This obligation is not included in the above table. SouthStar also had capacity commitments related to the purchase of transportation rights on interstate pipelines.

We also have incurred various contingent financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The following table illustrates our expected contingent financial commitments as of December 31, 2004:

			Commitments Due Before December 31,		
In millions	Total	2005	2006 & 2007	2008 & 2009	2010 & Thereafter
Guarantees[1]	$ 7	$ 7	$—	$—	$—
Standby letters of credit and performance/surety bonds	12	12	—	—	—
Total	$19	$19	$—	$—	$—

[1] We provide a guarantee on behalf of our subsidiary, SouthStar. We guarantee 70% of SouthStar's obligations to Southern Natural Gas Company (Southern Natural) under certain agreements between the parties up to a maximum of $7 million if SouthStar fails to make payment to Southern Natural. We have certain guarantees that are recorded on our consolidated balance sheet that would not cause any additional impact on our financial statements beyond what was already recorded.

RENTAL EXPENSE AND SUBLEASE INCOME

The following table illustrates our total rental lease expenses and sublease credits incurred for property and equipment:

In millions	2004	2003	2002
Rental expense	**$22**	$22	$20
Sublease income	**—**	—	(2)

LITIGATION

We are involved in litigation arising in the normal course of business. We believe the ultimate resolution of such litigation will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. Changes to the status of previously disclosed litigation are as follows:

NUI Shareholder Complaint

In September 2004, a shareholder class action complaint (Complaint) was filed in a civil action captioned *Green Meadows Partners, LLP on behalf of itself and all others similarly situated v. Robert P. Kenney, Bernard S. Lee, Craig G. Mathews, Dr. Vera King Farris, James J. Forese, J. Russell Hawkins, R. Van Whisnand, John Kean, NUI and the Company,* pending in the Superior Court of the State of New Jersey, County of Somerset, Law Division. The Complaint, brought on behalf of a potential class of the stockholders of NUI, names as defendants all of the directors of NUI (Individual Defendants), NUI and the Company.

The Complaint alleges that purported financial incentives in the form of change of control payments and indemnification rights created a conflict of interest on the part of certain of the Individual Defendants in evaluating a possible sale of NUI. The Complaint further alleges that the Individual Defendants, aided and abetted by the Company, breached fiduciary duties owed to the plaintiff and the potential class. The Complaint demands judgment (i) determining that the action is properly maintainable as a class action, (ii) declaring that the Individual Defendants breached fiduciary duties owed to the plaintiff and the potential class, aided and abetted by the Company, (iii) enjoining the sale of NUI, or if consummated, rescinding the sale, (iv) eliminating the $7.5 million break-up fee with the Company, (v) awarding the plaintiff and the potential class compensatory and/or rescissory damages, (vi) awarding interest, attorney's fees, expert fees and other costs, and (vii) granting such other relief as the Court may find just and proper.

On October 12, 2004, we reached an agreement in principle with Green Meadows Partners, LLP to settle this litigation. The settlement called for NUI to provide certain additional information and disclosures to its shareholders, as reflected in the "Additional Disclosure" section of NUI's proxy statement supplement, filed on October 12, 2004 with the SEC. In addition, as part of the settlement, NUI and the Company consented to a settlement class that consists of persons holding shares of NUI common stock at any time from July 15, 2004 until November 30, 2004, and we agreed to pay plaintiff's attorney's fees and costs in the amount of $285,000. No part of these attorney's fees or costs will be paid out of funds that would otherwise have been paid to NUI's shareholders.

On December 22, 2004, the trial court entered an order conditionally certifying a class for settlement purposes and designating the Plaintiff as a Settlement Class representative. The trial court's order also established deadlines for Defendants to provide notice to the Settlement Class, for Settlement Class members to object to the settlement and for a final Settlement Hearing.

Note 11
FAIR VALUE OF FINANCIAL INSTRUMENTS

The following table shows the carrying amounts and fair values of financial instruments included in our consolidated balance sheets:

In millions	Carrying Amount	Estimated Fair Value
As of December 31, 2004		
Long-term debt including current portion	**$1,623**	**$1,816**
As of December 31, 2003		
Long-term debt including current portion	1,033	1,166

The estimated fair values are determined based on interest rates that are currently available for issuance of debt with similar terms and remaining maturities. For the notes payable to Trusts, we used quoted market prices and dividend rates for preferred stock with similar terms.

Considerable judgment is required to develop the fair value estimates; therefore, the values are not necessarily indicative of the amounts that could be realized in a current market exchange. The fair value estimates are based on information available to management as of December 31, 2004. We are not aware of any subsequent factors that would significantly affect the estimated fair value amounts. For more information about the fair values of our interest rate swaps, see Note 4.

Note 12
INCOME TAXES

We have two categories of income taxes in our statements of consolidated income: current and deferred. Current income tax expense consists of federal and state income tax less applicable tax credits related to the current year. Deferred income tax expense generally is equal to the changes in the deferred income tax liability and regulatory tax liability during the year.

INVESTMENT TAX CREDITS

Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our consolidated balance sheets (see Note 5). These investment tax credits are being amortized over the estimated life of the related properties as credits to income in accordance with regulatory treatment. We reduce income tax expense in our statements of consolidated income for the investment tax credits and other tax credits associated with our nonregulated subsidiaries. Components of income tax expense shown in the statements of consolidated income are as follows:

In millions	2004	2003	2002
Included in expenses			
Current income taxes			
Federal	**$25**	$20	$(19)
State	**1**	13	(4)
Deferred income taxes			
Federal	**60**	52	79
State	**5**	3	3
Amortization of investment tax credits	**(1)**	(1)	(1)
Total	**$90**	$87	$ 58

The reconciliations between the statutory federal income tax rate, the effective rate and the related amount of tax for the years ended December 31, 2004, 2003 and 2002 are presented below:

Dollars in millions	2004 Amount	2004 % of Pretax Income	2003 Amount	2003 % of Pretax Income	2002 Amount	2002 % of Pretax Income
Computed tax expense	**$85**	**35.0%**	$78	35.0%	$56	35.0%
State income tax, net of federal income tax benefit	**9**	**3.5**	8	3.8	4	2.4
Amortization of investment tax credits	**(1)**	**(0.6)**	(1)	(0.6)	(1)	(0.8)
Flexible dividend deduction	**(2)**	**(0.6)**	(1)	(0.6)	(2)	(0.9)
Other — net	**(1)**	**(0.2)**	3	1.4	1	0.3
Total income tax expense	**$90**	**37.1%**	$87	39.0%	$58	36.0%

ACCUMULATED DEFERRED INCOME TAX ASSETS AND LIABILITIES

We report some of our assets and liabilities differently for financial accounting purposes than we do for income tax purposes. The tax effects of the differences in those items are reported as deferred income tax assets or liabilities in our consolidated balance sheets. The assets and liabilities are measured utilizing income tax rates that are currently in effect. Because of the regulated nature of the utilities' business, a regulatory tax liability has been recorded in accordance with SFAS No. 109, "Accounting for Income Taxes" (SFAS 109). The regulatory tax liability is being amortized over approximately 30 years (see Note 5). Our deferred tax asset includes an additional pension liability of $34 million, which increased $7 million from 2003 in accordance with SFAS 109 (see Note 6).

As indicated in the table below, our deferred tax assets and liabilities include certain items we acquired from NUI. We have provided a valuation allowance for some of these items that reduces our net deferred tax assets to amounts we believe are more likely than not to be realized in future periods. With respect to our continuing operations, we have net operating losses in various jurisdictions. Components that give rise to the net accumulated deferred income tax liability are as follows:

In millions	As of Dec 31, 2004	As of Dec 31, 2003
Accumulated deferred income tax liabilities		
Property — accelerated depreciation and other property-related items	**$323**	$294
Other	**238**	125
Total accumulated deferred income tax liabilities	**561**	419
Accumulated deferred income tax assets		
Deferred investment tax credits	**8**	7
Deferred pension additional minimum liability	**34**	27
Net operating loss — NUI[1]	**31**	—
Net operating loss — Virginia Gas Company[2]	**6**	—
Capital loss carryforward	**5**	—
Alternative minimum tax credit[3]	**7**	—
Other	**41**	9
Total accumulated deferred income tax assets	**132**	43
Valuation allowances	**(8)**	—
Total accumulated deferred income tax assets, net of valuation allowance	**124**	43
Net accumulated deferred tax liability	**$437**	$376

[1] Includes NUI's federal net operating loss carryforwards of approximately $79 million that expire in 2024.

[2] Includes Virginia Gas Company's $18 million pre-acquisition net operating losses, which are subject to an Internal Revenue Service Section 382 limitation (or reduced amount available for deduction as a result of change in control) and expire in 2016 through 2020.

[3] Was generated by NUI and can be carried forward indefinitely to reduce our future tax liability.

Note 13

RELATED PARTY TRANSACTIONS

We previously recognized revenue and had accounts receivable from our affiliate, SouthStar, as detailed on the table below. As a result of our adoption of FIN 46R on January 1, 2004, we consolidated all of SouthStar's accounts with our subsidiaries' accounts and eliminated any intercompany balances between segments. For more discussion of FIN 46R and the impact of its adoption on our consolidated financial statements, see Note 3.

In millions	2004	2003	2002
Recognized revenue	$—	$169	$171
Accounts receivable	$—	11	—

Note 14

SEGMENT INFORMATION

Our business is organized into three operating segments:

- Distribution operations consists primarily of Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, Florida Gas and Virginia Natural Gas.
- Wholesale services consists primarily of Sequent.
- Energy investments consists primarily of SouthStar, Pivotal Jefferson Island, Pivotal Propane, Virginia Gas Company and AGL Networks.

We treat corporate, our fourth segment, as a nonoperating business segment that consists primarily of AGL Resources Inc., AGL Services Company, nonregulated financing and captive insurance subsidiaries and the effect of intercompany eliminations. We eliminated intersegment sales for the years ended December 31, 2004, 2003 and 2002 from our statements of consolidated income.

We evaluate segment performance based primarily on the non-GAAP measure of earnings before interest and taxes (EBIT), which includes the effects of corporate expense allocations. EBIT is a non-GAAP measure that includes operating income, other income, equity in SouthStar's income in 2003 and 2002, donations, minority interest in 2004 and gains on sales of assets. Items that we do not include in EBIT are financing costs, including interest and debt expense, income taxes and the cumulative effect of a change in accounting principle, each of which we evaluate on a consolidated level. We believe EBIT is a useful measurement of our performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations.

You should not consider EBIT an alternative to, or a more meaningful indicator of our operating performance than, operating income or net income as determined in accordance with GAAP. In addition, our EBIT may not be comparable to a similarly titled measure of another company. The reconciliations of EBIT to operating income and net income for the years ended December 31, 2004, 2003 and 2002 are presented below:

In millions	2004	2003	2002
Operating revenues	**$1,832**	$983	$877
Operating expenses	**1,500**	741	660
Gain on sale of Caroline Street campus	**—**	16	—
Operating income	**332**	258	217
Other income	**—**	40	30
Minority interest	**(18)**	—	—
EBIT	**314**	298	247
Interest expense	**71**	75	86
Earnings before income taxes	**243**	223	161
Income taxes	**90**	87	58
Income before cumulative effect of change in accounting principle	**153**	136	103
Cumulative effect of change in accounting principle	**—**	(8)	—
Net income	**$ 153**	$128	$103

Summarized income statement, balance sheet and capital expenditure information by segment as of and for the years ended December 31, 2004, 2003 and 2002 are shown in the following tables:

In millions	Distribution Operations	Wholesale Services	Energy Investments	Corporate and Intersegment Eliminations	Consolidated AGL Resources
2004					
Operating revenues from external parties	$ 926	$ 54	$852	$ –	$1,832
Intersegment revenues[1]	185	–	–	(185)	–
Total revenues	1,111	54	852	(185)	1,832
Operating expenses					
Cost of gas	470	1	707	(184)	994
Operation and maintenance	286	27	65	(1)	377
Depreciation and amortization	85	1	4	9	99
Taxes other than income taxes	24	1	1	4	30
Total operating expenses	865	30	777	(172)	1,500
Operating income (loss)	246	24	75	(13)	332
Earnings in equity interests	–	–	2	–	2
Minority interest	–	–	(18)	–	(18)
Other income (loss)	1	–	–	(3)	(2)
EBIT	$ 247	$ 24	$ 59	$ (16)	$ 314
Identifiable assets	$4,386	$696	$630	$ (86)	$5,626
Investment in joint ventures	–	–	235	(221)	14
Total assets	$4,386	$696	$865	$(307)	$5,640
Goodwill	$ 340	$ –	$ 14	$ –	$ 354
Capital expenditures	$ 205	$ 8	$ 40	$ 11	$ 264

In millions	Distribution Operations	Wholesale Services	Energy Investments	Corporate and Intersegment Eliminations	Consolidated AGL Resources
2003					
Operating revenues[1]	$ 936	$ 41	$ 6	$ –	$ 983
Operating expenses					
Cost of gas	337	1	1	–	339
Operation and maintenance	261	20	9	(7)	283
Depreciation and amortization	81	–	1	9	91
Taxes other than income taxes	24	–	–	4	28
Total operating expenses	703	21	11	6	741
Gain (loss) on sale of Caroline Street campus[2]	21	–	–	(5)	16
Operating income (loss)	254	20	(5)	(11)	258
Donation to private foundation	(8)	–	–	–	(8)
Earnings in equity interests	–	–	48	–	48
Other income (loss)	1	–	–	(1)	–
EBIT	$ 247	$ 20	$ 43	$(12)	$ 298
Identifiable assets	$3,325	$460	$ 90	$ 2	$3,877
Investment in joint ventures	–	–	101	–	101
Total assets	$3,325	$460	$191	$ 2	$3,978
Goodwill	$ 177	$ –	$ –	$ –	$ 177
Capital expenditures	$ 126	$ 2	$ 8	$ 22	$ 158

In millions	Distribution Operations	Wholesale Services	Energy Investments	Corporate and Intersegment Eliminations	Consolidated AGL Resources
2002					
Operating revenues[1]	$ 852	$ 23	$ 2	$ —	$ 877
Operating expenses					
Cost of gas	267	—	—	1	268
Operation and maintenance	255	13	8	(2)	274
Depreciation and amortization	82	—	—	7	89
Taxes other than income taxes	25	1	1	2	29
Total operating expenses	629	14	9	8	660
Operating income (loss)	223	9	(7)	(8)	217
Interest income	1	—	—	—	1
Earnings in equity interests	—	—	27	—	27
Other income (loss)	1	—	4	(3)	2
EBIT	$ 225	$ 9	$ 24	$(11)	$ 247
Identifiable assets	$3,150	$364	$107	$ 46	$3,667
Investment in joint ventures	—	—	75	—	75
Total assets	$3,150	$364	$182	$ 46	$3,742
Capital expenditures	$ 128	$ 1	$ 29	$ 29	$ 187

[1] Intersegment revenues – Wholesale services records its energy marketing and risk management revenue on a net basis. The following table provides detail of wholesale services' total gross revenues and gross sales to distribution operations:

In millions	Third party Gross Revenues	Intersegment Revenues	Total Gross Revenues
2004	**$4,378**	**$369**	**$4,747**
2003	3,298	353	3,651
2002	1,639	131	1,770

[2] The gain before income taxes of $16 million on the sale of our Caroline Street campus was recorded as operating income (loss) in two of our segments. A gain of $21 million on the sale of the land was recorded in distribution operations, and a write-off of $(5) million on the buildings and their contents was recorded in our corporate segment.

Note 15

QUARTERLY FINANCIAL DATA (UNAUDITED)

Our quarterly financial data for 2004, 2003 and 2002 are summarized below. The variance in our quarterly earnings is the result of the seasonal nature of our primary business.

In millions, except per share amounts	Mar 31	Jun 30	Sep 30	Dec 31
2004				
Operating revenues	**$ 651**	**$ 294**	**$ 262**	**$ 625**
Operating income	**133**	**53**	**46**	**100**
Net income	**66**	**21**	**20**	**46**
Basic earnings per share	**1.02**	**0.34**	**0.31**	**0.64**
Fully diluted earnings per share	**1.00**	**0.33**	**0.31**	**0.64**
2003				
Operating revenues	$ 353	$ 187	$ 166	$ 278
Operating income	101	41	58	58
Income before cumulative effect of change in accounting principle	60	19	22	35
Net income	52	19	22	35
Basic earnings per share before cumulative change in accounting principle	0.99	0.30	0.35	0.54
Basic earnings per share	0.86	0.30	0.35	0.54
Fully diluted earnings per share before cumulative change in accounting principle	0.98	0.29	0.34	0.54
Fully diluted earnings per share	0.85	0.29	0.34	0.54
2002				
Operating revenues	$ 272	$ 161	$ 193	$ 251
Operating income	74	42	38	63
Net income	50	12	10	31
Basic earnings per share	0.90	0.22	0.17	0.55
Fully diluted earnings per share	0.89	0.22	0.17	0.55

Our basic and fully diluted earnings per common share are calculated based on the weighted daily average number of common shares and common share equivalents outstanding during the quarter. Those totals differ from the basic and fully diluted earnings per share as shown on the statements of consolidated income, which are based on the weighted average number of common shares and common share equivalents outstanding during the entire year.

MANAGEMENT'S REPORTS ON INTERNAL CONTROL OVER FINANCIAL REPORTING

AGL RESOURCES INC.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We excluded Jefferson Island Storage & Hub, LLC and NUI Corporation from our assessment of internal control over financial reporting as of December 31, 2004 because they were acquired by us in purchase business combinations during the fourth quarter of 2004. Jefferson Island Storage & Hub, LLC's and NUI Corporation's total assets represents $86 million and $1,352 million, and total revenues represents $11 million and $86 million, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2004.

Based on our evaluation under the framework in *Internal Control—Integrated Framework* issued by COSO, our management concluded that our internal control over financial reporting was effective as of December 31, 2004. Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which insofar as it relates to the effectiveness of SouthStar Energy Services LLC is based solely upon the report of other auditors and is included herein.

Paula Rosput Reynolds

Paula Rosput Reynolds
Chairman, President and Chief Executive Officer

Richard T. O'Brien

Richard T. O'Brien
Executive Vice President and Chief Financial Officer

February 14, 2005

SOUTHSTAR ENERGY SERVICES LLC

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and in accordance with, Public Company Accounting Oversight Board's Auditing Standard No. 2, *An Audit of Internal Control Over Financial Reporting Performed in Conjunction With an Audit of Financial Statements*. Based on our evaluation under the framework in *Internal Control—Integrated Framework*, our management concluded that our internal control over financial reporting was effective as of December 31, 2004.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Michael A. Braswell
President, SouthStar Energy Services LLC

Michael A. Degnan
Director, Finance & Accounting, SouthStar Energy Services LLC

February 2, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF AGL RESOURCES INC.:

We have completed an integrated audit of AGL Resources Inc.'s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits and the reports of other auditors, are presented below.

Consolidated financial statements

In our opinion, based on our audits and the report of other auditors, the accompanying consolidated balance sheets and statements of income, common shareholders' equity, and cash flows present fairly, in all material respects, the financial position of AGL Resources Inc. and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of SouthStar Energy Services LLC, a joint venture in which a subsidiary of the Company has a non-controlling 70% financial interest, which statements reflect total assets of $243 million and total revenues of $827 million as of and for the year ended December 31, 2004. The Company's equity investment in SouthStar Energy Services LLC was $71 million and equity in earnings was $46 million as of and for the year ended December 31, 2003. Those statements were audited by other auditors whose report thereon has been furnished to us, and our opinion expressed herein, insofar as it relates to the amounts included for SouthStar Energy Services LLC., is based solely on the report of the other auditors. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits and the report of other auditors provide a reasonable basis for our opinion.

As discussed in Note 3 to the consolidated financial statements, effective January 1, 2003, AGL Resources Inc. and subsidiaries adopted EITF No. 02-03, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.* As discussed in Note 3 to the consolidated financial statements, effective January 1, 2003, AGL Resources Inc. and subsidiaries adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations.* As discussed in Note 3 to the consolidated financial statements, effective January 1, 2004, AGL Resources Inc. and subsidiaries adopted Financial Accounting Standards Board (FASB) Interpretation No. 46-R, "Consolidation of Variable Interest Entities".

Internal control over financial reporting

Also, in our opinion, based on our audit and the report of other auditors, management's assessment, included in Management's Report on Internal Control Over Financial Reporting related to AGL Resources Inc. appearing on page 107 of AGL Resources, Inc Annual Report to Shareholders, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, based on our audit and the report of other auditors, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We did not examine the effectiveness of internal control of SouthStar Energy Services LLC as of December 31, 2004. The effectiveness of SouthStar Energy Services LLC's internal control over financial reporting was audited by other auditors whose report has been furnished to us, and our opinions expressed herein, insofar as they relate to the effectiveness of SouthStar Energy Services LLC's internal control over financial reporting are based solely on the report of the other auditors. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM (CONTINUED)

and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit and the report of the other auditors provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Report on Internal Control over Financial Reporting, management has excluded Jefferson Island Storage & Hub LLC and NUI Corporation from its assessment of internal control over financial reporting as of December 31, 2004 because they were acquired by the Company in purchase business combinations during 2004. We have also excluded Jefferson Island Storage & Hub LLC and NUI Corporation from our audit of internal control over financial reporting. Jefferson Island Storage & Hub LLC and NUI Corporation are wholly owned subsidiaries whose total assets represent $86 million and $1,352 million and total revenues represent $11 million and $86 million, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2004.

PricewaterhouseCoopers LLP

Atlanta, Ga.
February 14, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

THE EXECUTIVE COMMITTEE AND MEMBERS OF SOUTHSTAR ENERGY SERVICES LLC

We have audited management's assessment, included in the accompanying Report of Management on Internal Control Over Financial Reporting, that SouthStar Energy Services LLC ("SouthStar") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). SouthStar's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that SouthStar maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, SouthStar maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the balance sheets of SouthStar as of December 31, 2004 and 2003, and the related statements of income, changes in members' capital, and cash flows for each of the three years in the period ended December 31, 2004 of SouthStar and our report dated February 4, 2005 expressed an unqualified opinion thereon.

Ernst & Young LLP

Atlanta, Georgia
February 4, 2005

REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRMS

THE EXECUTIVE COMMITTEE AND MEMBERS SOUTHSTAR ENERGY SERVICES LLC

We have audited the balance sheets of SouthStar Energy Services LLC (the Company) as of December 31, 2004 and 2003, and the related statements of income, changes in members' capital, and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of SouthStar Energy Services LLC at December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004 in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of SouthStar Energy Services LLC's internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 4, 2005 expressed an unqualified opinion thereon.

Ernst & Young LLP

Atlanta, Georgia
February 4, 2005

TO THE SHAREHOLDERS AND BOARD OF DIRECTORS OF AGL RESOURCES INC.:

We have audited the accompanying consolidated statements of income, shareholders' equity, and cash flows for the year ended December 31, 2002 of AGL Resources Inc. and subsidiaries (the "Company"). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the results of operations and cash flows of AGL Resources Inc. and subsidiaries for the year ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
January 27, 2003

SHAREHOLDER INFORMATION

CORPORATE HEADQUARTERS

AGL Resources Inc., Ten Peachtree Place, N.E., Atlanta, GA 30309; 404-584-4000; website: aglresources.com

TRANSFER AGENT AND REGISTRAR

EquiServe serves as our transfer agent and registrar and can help with a variety of stock-related matters, including name and address changes; transfer of stock ownership; lost certificates; and Form 1099s.

Inquiries may be directed to: AGL Resources Shareholder Services, c/o EquiServe Trust Company, N.A., P.O. Box 43010, Providence, RI 02190-3010. Toll-free: 800-633-4236; website: equiserve.com

AVAILABLE INFORMATION

A copy of this Annual Report, as well as our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, other reports that we file with or furnish to the Securities and Exchange Commission (SEC) and our recent news releases are available free of charge on the internet at our website aglresources.com as soon as reasonably practicable after we electronically file such reports with, or furnish such reports to, the SEC. These reports and news releases are available on our website or through a toll-free interactive shareholder information line at 877-ATG-NYSE (877-284-6973). The information contained on our website does not constitute incorporation by reference of the information contained on the website and should not be considered part of this document.

Our Annual Report on Form 10-K includes the certifications of our chief executive officer and chief financial officer required by Sections 302 and 906 of the Sarbanes-Oxley Act of 2002. Additionally, we filed with the New York Stock Exchange the certification by our chief executive officer that she is not aware of any violation of New York Stock Exchange corporate governance listing standards.

Our corporate governance guidelines; our code of ethics; our code of business conduct; and the charters of our Board committees, including the audit, compensation and management development, corporate development, environmental and corporate responsibility, executive, finance and risk management and nominating and corporate governance committees, are available on our website.

The above information will also be furnished free of charge upon written request to our Investor Relations department at: AGL Resources, Investor Relations, Dept. 1071, Ten Peachtree Place, N.E., Atlanta, GA 30309; 404-584-4414

INSTITUTIONAL INVESTOR INQUIRIES

Institutional investors and securities analysts should direct inquiries to: Brian Little, Director, Investor Relations, c/o AGL Resources, Investor Relations, Dept. 1071, Ten Peachtree Place, N.E., Atlanta, GA 30309; 404-584-4414; blittle@aglresources.com

ANNUAL MEETING

The 2005 annual meeting of shareholders will be held Wednesday, April 27, 2005, at Ten Peachtree Place, N.E., Atlanta, Georgia 30309.

RESOURCESDIRECT™

New investors may make an initial investment, and shareholders of record may acquire additional shares of our common stock, through ResourcesDIRECT™ without paying brokerage fees or service charges. Initial cash investments, quarterly cash dividends and/or optional cash purchases may be invested through the plan, subject to certain requirements. To obtain a copy of the plan prospectus and enrollment materials, contact our transfer agent, call our toll-free interactive shareholder line at 877-ATG-NYSE (877-284-6973) or visit our website at aglresources.com.

STOCK PRICE AND DIVIDEND INFORMATION

Our common stock is listed on the New York Stock Exchange under the symbol ATG. At January 20, 2005, there were approximately 11,135 record holders of our common stock. Quarterly information concerning our high and low prices and cash dividends that we paid in 2004 and 2003 is as follows:

2004

	Sales Price of Common Stock		Cash Dividend
Quarter ended	High	Low	per Common Share
March 31, 2004	**$30.63**	**$27.87**	**$0.28**
June 30, 2004	**29.41**	**26.50**	**$0.29**
September 30, 2004	**31.27**	**28.60**	**$0.29**
December 31, 2004	**33.65**	**30.11**	**$0.29**

2003

	Sales Price of Common Stock		Cash Dividend
Quarter ended	High	Low	per Common Share
March 31, 2003	$25.41	$21.90	$0.27
June 30, 2003	26.98	23.30	$0.28
September 30, 2003	28.49	25.35	$0.28
December 31, 2003	29.35	27.24	$0.28

We pay dividends four times a year: March 1, June 1, September 1 and December 1. We have paid 229 consecutive quarterly dividends beginning in 1948. Dividends are declared at the discretion of our Board of Directors, and future dividends will depend on our future earnings, cash flow, financial requirements and other factors. In February 2005, we increased the quarterly dividend to $0.31 per common share.

PREFERRED SECURITIES

Our preferred securities are listed and traded on the New York Stock Exchange under the ticker symbol ATG_P.

DIRECTORS AND OFFICERS

Board of Directors

pictured in left column

Wyck A. Knox, Jr.[1*,5,6]
Partner
Kilpatrick Stockton LLP
Augusta, GA
Director since 1998

Michael J. Durham[1*,4]
Founder, President and
Chief Executive Officer
Cognizant Associates, Inc.
Dallas, TX
Director since 2003

Henry C. Wolf[1,4]
Vice Chairman and
Chief Financial Officer
Norfolk Southern Corporation
Norfolk, VA
Director since 2004

Thomas D. Bell, Jr.[2,7]
Vice Chairman, President and
Chief Executive Officer
Cousins Properties Incorporated
Atlanta, GA
Director since 2004

Bettina M. Whyte[2,3,7]
Managing Director
AlixPartners, LLC
New York, NY
Director since 2004

James A. Rubright[2,3,5,6*]
Chairman and
Chief Executive Officer
Rock-Tenn Company
Norcross, GA
Director since 2001

pictured in right column

Felker W. Ward, Jr.[5,6,7*]
Chairman
Pinnacle Investment Advisors, Inc.
Union City, GA
Director since 1988

Charles R. Crisp[3*,6,7]
Former President, Chief Executive
Officer and Director of Coral Energy,
a subsidiary of Shell Oil Company
Houston, TX
Director since 2003

Paula Rosput Reynolds[3,4,5,6]
Chairman, President and
Chief Executive Officer
AGL Resources Inc.
Atlanta, GA
Director since 2000

Dennis M. Love[1,7]
President and
Chief Executive Officer
Printpack Inc.
Atlanta, GA
Director since 1999

D. Raymond Riddle[1,2,5*]
Retired Chairman and
Chief Executive Officer
National Service Industries, Inc.
Atlanta, GA
Director since 1978

Arthur E. Johnson[2*,4]
Senior Vice President
Lockheed Martin Corporation
Bethesda, MD
Director since 2002

[*] Committee chair

[1] Audit, [2] Compensation and Management Development, [3] Corporate Development, [4] Environmental and Corporate Responsibility, [5] Executive, [6] Finance and Risk Management, [7] Nominating and Corporate Governance.

All members of the Audit, Compensation and Management Development, and Nominating and Corporate Governance Committees are "independent" as defined under applicable rules and regulations.

Executive Officers

Paula Rosput Reynolds, Chairman, President and Chief Executive Officer

Richard T. O'Brien, Executive Vice President and Chief Financial Officer

Kevin P. Madden, Executive Vice President of Distribution and Pipeline Operations

Paul R. Shlanta, Senior Vice President, General Counsel
and Chief Corporate Compliance Officer

Melanie M. Platt, Senior Vice President, Human Resources

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Nov 27 2007 3:49PM ET

Distribution Operations

AGL Resources' core business is delivering environmentally friendly natural gas to the company's 2.2 million customers through its six utilities. With its signature "same day/next day" service, AGL Resources is committed to excellence in customer relations.

Here is an overview of the company's six utilities:

Atlanta Gas Light | Chattanooga Gas | Elizabethtown Gas | Elkton Gas | Florida City Gas | Virginia Natural Gas

Elizabethtown Gas

Elizabethtown Gas
Founded: 1855
Headquarters: Union, New Jersey
President: Jodi Gidley
Joined AGL Resources: 2004
Number of Customers: 269,000
Communities Served: Union, Middlesex, Sussex, Warren, Hunterdon, Morris and Mercer counties.
Web Address: http://www.elizabethtowngas.com

Elizabethtown Gas delivers service to more than 269,000 residential, business and industrial natural gas customers in New Jersey. The utility serves parts of Union, Middlesex, Sussex, Warren, Hunterdon, Morris and Mercer counties. Services include:

- Maintaining the gas pipeline infrastructure
- Responding to and repairing gas leaks
- Selling natural gas service to residential, commercial and industrial customers
- Providing customer service and billing customers for gas service
- Offering online customer information about natural gas and gas-fueled products

Elizabethtown Gas contributes to the communities it serves through employee volunteerism and donations to energy assistance programs and nonprofit agencies.

More information on AGL Resources' New Jersey utility can be found at ElizabethtownGas.com.

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SECURITIES AND EXCHANGE COMMISSION

(Release No. 35-27917; 70-10243)

AGL Resources, Inc. et al

Order Authorizing Acquisition of NUI Corporation and its Subsidiaries, Various Financing Transactions; Reservation of Jurisdiction

November 24, 2004

AGL Resources Inc. ("AGL Resources"), a registered public utility holding company, AGL Resources' subsidiary service company, AGL Services Company ("AGL Services"), both of Atlanta, GA, AGL Resources' gas utility subsidiaries, Atlanta Gas Light Company ("AGLC"), Atlanta, GA, Chattanooga Gas Company ("CGC"), Chattanooga, TN and Virginia Natural Gas, Inc. ("VNG"), Norfolk, VA; NUI Corporation ("NUI"), a New Jersey corporation and currently a public utility holding company claiming exemption under section 3(a)(1) of the Act by rule 2 under the Act; NUI's two gas public utility subsidiaries ("NUI Utility Subsidiaries"), NUI Utilities, Inc. ("NUI Utilities") and Virginia Gas Distribution Company ("VGDC"); and NUI's direct and indirect nonutility subsidiaries ("NUI Nonutilities" and together with the NUI Utility Subsidiaries, "NUI Subsidiaries") NUI Capital Corp. ("NUI Capital"), Utility Business Services, Inc. ("UBS") Virginia Gas Company ("VGC"), Virginia Gas Storage Company, Virginia Gas Pipeline Company ("VGPC"), NUI Saltville Storage, Inc. ("NUISS"), NUI Storage, Inc. ("NUI Storage"), NUI Service, Inc.; NUI Energy, Inc. ("NUI Energy"), NUI Energy Brokers, Inc.("NUI Energy Brokers"), NUI Energy Solutions, Inc., OAS Group, Inc. ("OAS"), NUI Sales Management, Inc., TIC Enterprises, LLC ("TIC"), NUI Richton Storage, Inc., Richton Gas Storage Company, LLC; NUI/Caritrade International LLC, NUI Hungary, Inc., and NUI International, Inc., all of Bedminster, NJ (collectively with AGL Resources, AGL Services, AGLC, CGC and VNG, "Applicants"), have filed an application-declaration ("Application") with the Securities and Exchange Commission ("Commission") under sections 3(a)(1), 5, 6(a), 7, 9(a), 10, 11, 12(b), 12(c) and 13(b) of the Public Utility Holding Company Act of 1935, as amended ("Act") and rules 16, 43, 45, 46, 54 and 88, 90 and 91under the Act. The Commission issued a notice of the Application on October 28, 2004 (HCAR No. 27905).

AGL proposes to acquire all of the issued and outstanding common stock of NUI and indirectly acquire the NUI Subsidiaries. Applicants also propose that NUI and the NUI Subsidiaries engage in certain financings and other transactions.

I. Description of the Parties

A. AGL Resources and its Subsidiaries

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1. AGL Resources

Applicants state that AGL Resources is a corporation organized under the laws of Georgia, and is an Atlanta-based energy services holding company. AGL Resources owns three gas public utility subsidiary companies: AGLC, CGC and VNG which serve more than 1.8 million customers in three states (collectively, "AGL Resources Utilities").

Applicants state that AGL Resources' common stock has a five dollar par value and as of June 30, 2004, AGL Resources had 64,923,654 shares of common stock issued and outstanding. As of and for the six months ended June 30, 2004, AGL Resources had total assets of $4.01 billion, net utility plant assets of $2.26 billion, total operating revenues of $945 million, operating income of $186 million and net income of $87 million.

a) AGL Resources' Utilities

(1) AGLC

Applicants state that AGLC is a natural gas local distribution utility with distribution systems and related facilities serving 237 cities throughout Georgia, including Atlanta, Athens, Augusta, Brunswick, Macon, Rome, Savannah and Valdosta. AGLC also has approximately 6.0 billion cubic feet, or Bcf, of liquefied natural gas ("LNG") storage capacity in three LNG plants to supplement the supply of natural gas during peak usage periods. The Georgia Public Service Commission regulates AGLC with respect to rates, maintenance of accounting records and various other service and safety matters. Applicants state that as of and for the six months ended June 30, 2004, AGLC had total assets of $2.41 billion, total operating revenues of $308 million and net income of $76 million. AGLC owns all of the outstanding stock of AGL Rome Holdings, Inc.

b) CGC

Applicants state that CGC is a natural gas local distribution utility with distribution systems and related facilities serving twelve cities and surrounding areas, including the Chattanooga and Cleveland areas of Tennessee. CGC also has approximately 1.2 Bcf of LNG storage capacity in its LNG plant. The Tennessee Regulatory Authority regulates CGC with respect to rates, maintenance of accounting records and various other service and safety matters. As of and for the six months ended June 30, 2004, CGC had total assets of $147 million, total operating revenues of $55 million and net income of $7.0 million.

(1) VNG

Applicants state that VNG is a natural gas local distribution utility with distribution systems and related facilities serving eight cities in the Hampton Roads region of southeastern Virginia. VNG owns and operates approximately 155 miles of a separate high-pressure pipeline that provides delivery of gas to customers under firm transportation agreements within the state of Virginia. VNG also has approximately 5.0 million gallons of propane storage capacity in its two propane facilities to supplement the supply of natural gas during peak usage periods. The Virginia State Corporation Commission ("VSCC") regulates VNG with respect to rates, maintenance of accounting records and various other service and safety matters. Applicants state that as of and for the six months ended June 30, 2004, VNG had total assets of $736 million, total operating revenues of $210 million and net income of $21 million.

B. AGL Nonutilities

AGL Resources also holds direct and indirect interests in nonutility companies ("AGL Nonutilities" and together with the AGL Utilities, "AGL Subsidiaries") whose retention has been authorized by order dated October 5, 2000 (HCAR No. 27243), ("AGL Merger Order").

C. NUI

1. Utility Subsidiaries

Applicants state that NUI has two public utility subsidiary companies, NUI Utilities and VGDC. Through its subsidiaries, NUI operates natural gas distribution systems and natural gas storage and pipeline businesses.

a) NUI Utilities

Applicants state that NUI Utilities distributes natural gas to approximately 371,000 customers in New Jersey, Florida and Maryland through its three regulated utility divisions, Elizabethtown Gas Company ("Elizabethtown Gas"), City Gas Company of Florida ("City Gas") and Elkton Gas. Each division is subject to regulation by the public service commission in the states where it operates. Applicants state that, during fiscal year 2003, the operating revenues associated with the provision of distribution services by NUI Utilities' regulated utility divisions was approximately $484.8 million, representing 95% of the total operating revenues of NUI. Of this amount, 85% was generated by utility operations in New Jersey, where approximately 71% of NUI Utilities' customers are located. Total utility gas volumes sold or transported by such utility operations amounted to 63.7 Bcf, of which 87% was sold or transported in New Jersey.

Applicants state that NUI Utilities distributes gas through approximately 6,200 miles of steel, cast iron and plastic mains. The company has physical interconnections with five interstate pipelines in New Jersey and a single interstate pipeline in both Maryland and Florida. Common interstate pipelines along the company's operating system provide the company with the flexibility to manage pipeline capacity and supply, thereby optimizing system utilization.

Applicants state that, through its Elizabethtown Gas and City Gas divisions, NUI Utilities also has an appliance service, sales, leasing and financing businesses in New Jersey and Florida. The appliance group generated operating revenues of $11.4 million in fiscal year 2003 and had operating margins of $3.2 million in the same period.

b) VGDC

VGDC is an indirect wholly owned public utility subsidiary of NUI and a direct subsidiary of VGC, a holding company for certain utility and nonutility businesses. VGDC distributes gas to approximately 275 customers in Virginia. During fiscal year 2003, VGDC sold approximately 200.785 Mcf of gas, of which 4% was sold to residential customers and 96% to commercial and industrial customers.

2. Nonutility Subsidiaries

a) NUI Capital Corp.

Applicants state that the NUI Nonutilities' businesses are carried out primarily by NUI Capital and its subsidiaries. NUI Capital's only remaining nonutility subsidiary with substantial continuing operations is UBS, a billing and customer information systems and services subsidiary. Applicants state that NUI's other noutility subsidiaries are winding down their operations.[1] These subsidiaries include: NUI Energy, an energy retailer; NUI Energy Brokers, NUI's wholesale energy trading and portfolio management subsidiary; OAS, the company's digital mapping operation; and TIC, a sales outsourcing subsidiary that sold wireless and network telephone services.

Applicants state that UBS is a wholly owned subsidiary of NUI Capital. UBS provides outsourced customer information systems and services to NUI Utilities as well as investor-owned and municipal water/wastewater utilities. UBS offers customer and utility operations information systems and services, including account management, reporting, bill printing and mailing, and payment processing services. UBS presently serves 13 clients. Applicants state that UBS has been profitable in every year since 1995.

b) VGC

VGC is a natural gas storage, pipeline and distribution company with principal operations in Southwestern Virginia. In addition to owning VGDC, a gas utility described above, VGC operates two storage facilities; one a high-deliverability salt cavern facility in Saltville, Virginia ("Saltville Storage Project") and the other a depleted reservoir facility in Early Grove, Virginia. Combined, the facilities have approximately 2.6 Bcf of working gas capacity. VGC also owns and operates a 72-mile 8" intrastate pipeline and serves as the construction and operations manager for the Saltville Storage Project as discussed below. All of VGC's businesses are regulated by the VSCC, and the Saltville Storage Project is regulated by the Federal Energy Regulatory Commission ("FERC"). VGC, which was acquired by NUI in March 2001, had operating margins of $8.7 million in fiscal year 2003.

c) NUISS

NUI's wholly owned subsidiary, NUISS, is a fifty-percent member of SSLLC. SSLLC is a joint venture between subsidiaries of NUI and Duke Energy Gas Transmission ("DEGT") that is developing a natural gas storage facility in Saltville, Virginia. SSLLC plans to expand the present Saltville Storage Project from its current capacity of 1 Bcf to approximately 12 Bcf in several phases. The Saltville Storage Project connects to DEGT's East Tennessee Natural Gas interstate system and its Patriot pipeline. SSLLC is subject to regulation by FERC under the Natural Gas Act.

In conjunction with the development of the Saltville Storage Project, NUI Energy Brokers entered into a twenty-year agreement with DEGT for the firm transportation of natural gas in the Patriot pipeline and a twenty-year agreement with SSLLC for the firm storage of natural gas. NUI is not using the Patriot pipeline transportation capacity at this time since it has discontinued its trading operations.

d) NUI Storage

NUI Storage is a wholly owned subsidiary of NUI. Through its wholly owned subsidiaries, NUI Storage has acquired options on the land and mineral rights for property located in Richton, Perry County, Mississippi that the company plans to develop into a natural gas storage facility to help serve the Southeast United States. Like its companion storage facility in Saltville, Applicants expect Richton to offer the high-deliverability capabilities of salt dome storage for natural gas and will have access to a number of major interstate pipelines, including Destin Pipeline and its connections to Gulf South, Gulfstream, Florida Gas Transmission, SONAT, Tennessee Natural Gas and Transco. Through its connection to Destin Pipeline, Richton will have direct access to the gas supplies in the Gulf of Mexico, as well as supplies from the interconnected interstate pipelines referenced above. Richton can also serve as a potential storage facility for the various proposed liquefied natural gas projects in the Gulf Coast. Applicants anticipate that Richton will be subject to FERC regulation.

3. NUI and NUI Utilities' Capital Structure

The capital structures of NUI, VGDC and NUI Utilities as of June 30, 2004 are shown in the tables below.

	NUI ($MM)	% of total cap	NUI Utilities ($MM)	% of total cap
Long-term debt	199	28.4%	199	39.1 %
Short-term debt	294[2]	42.0%	86[3]	16.9 %
Common stock	207	29.6%	224	44.0%
Total capitalization	$70	100.0%	$501	100.0%

VGDC	($MM)	% of total cap
Long-term debt	0	0
Short-term debt	(1)[4]	50%
Common stock equity	(1)	50%
Total capitalization	(1)	100.0%

NUI and NUI Utilities state that they have the following ratings. Applicants state that VGDC has no rated debt.

	NUI	NUI Utilities
Moody's debt rating	Caa-1	B-1
Moody's outlook	Negative	Negative
S&P corporate credit rating		BB
S&P outlook		Credit Watch with developing implications

II. Description of the Transaction

A. The Merger

Applicants state that, on September 26, 2003, the Board of Directors of NUI announced its intention to pursue the sale of the company. Applicants have entered into an Agreement and Plan of Merger by and among AGL Resources Inc., Cougar Corporation[5] and NUI Corporation, dated as of July 14, 2004 ("Merger Agreement"), under which AGL Resources has agreed to acquire all the outstanding shares of NUI for $13.70 per share in cash, or $220 million in the aggregate based on approximately 16 million shares currently outstanding. AGL Resources will assume the outstanding indebtedness of NUI at closing. As of March 31, 2004, NUI had approximately $607 million in debt and $136 million of cash on its balance sheet, bringing the current net value of the acquisition to $691 million. AGL Resources anticipates that the amount of NUI debt and cash will change prior to the time of closing. Applicants state that NUI will register as a holding company under the Act by filing a Notification of Registration on Form U5A upon the consummation of the Merger.

B. Financing the Merger

By order dated April 1, 2004 (HCAR No. 27828) ("Financing Order"), the Commission authorized AGL Resources, the AGL Utilities and the AGL Nonutilities to engage in various financing transactions in an aggregate amount outstanding at any one time not to exceed $5 billion through March 31, 2007. AGL Resources is not requesting additional financing authorization to finance the purchase of NUI. AGL Resources has elected to finance the cash portion of the purchase price through the issuance of common stock at or prior to closing if market conditions are favorable. AGL Resources also must refinance a substantial portion of NUI and NUI Utilities' outstanding debt upon closing, due to "change in control" provisions included in these financings. AGL Resources expects to maintain its strong investment-grade rating and its current dividend policy post-acquisition. After the Merger, AGL Resources states that its' ratio of equity to total capitalization will remain well above 30%.

Applicants state that the Financing Order provides sufficient authority for AGL Resources to proceed in this fashion in the event that AGL Resources were to sell common stock and not close the NUI acquisition, the proceeds of the stock issuance would be used only for permitted corporate purposes.

C. Conditions

The transaction has been approved by NUI's shareholders, the Federal Communications Commission, and the New Jersey Board of Public Utilities ("NJBPU"), the Maryland Public Service Commission ("MPSC"), and the Virginia State Corporation Commission ("VSCC"). In addition, Applicants state that the transaction falls under the jurisdiction of the Federal Trade Commission ("FTC") and the Department of Justice ("DOJ") under the Hart-Scott-Rodino Antitrust Improvement Act of 1976 ("HSR Act").[6]

Applicants state that terms of the Merger Agreement also provide negotiated conditions for the consummation of the transaction that provide, among other things, that NUI shall have received orders approving the transaction from the above referenced state utility commissions that contain certain terms specified by AGL Resources, except as would not have a material adverse effect on NUI, NUI Utilities, or AGL Resources.

D. Management and Operations Following the Merger

Applicants state that under the Merger Agreement, AGL Resources has agreed to acquire NUI in a reverse triangular merger in which, at closing, a newly created subsidiary of AGL Resources will merge with and into NUI. Upon the consummation of the Merger, NUI will be a wholly owned direct subsidiary of AGL Resources. Applicants state that, upon closing NUI's current CEO, will leave the company. AGL Resources is evaluating the appropriate composition of NUI's senior management after closing as a part of the work of a combined AGL Resources and NUI transition team. The members of the NUI and NUI Utilities Boards of Directors will resign and new directors will be selected from the management of AGL Resources and its subsidiaries. The AGL Resources Board of Directors intends to add a New Jersey resident of significant professional stature and business qualification to the AGL Resources Board and AGL Resources has sought to have at least one Virginian business leader on its Board.

AGL Resources states that it is still evaluating personnel to fill key management positions and roles at NUI. AGL Resources intends to manage and govern NUI and NUI Utilities in the same manner in which it currently manages AGLC, CGC and VNG. At the corporate level, it is clear that there is some overlap among employees at AGL Resources, NUI and NUI Utilities, particularly in the "corporate services" area, including accounting, finance, legal, and public relations. AGL Resources and NUI have established an integration team that will identify redundancies that should be addressed as AGL Resources integrates NUI's corporate management into AGL Resources' existing management structure.

III. Affiliate Transactions

In the AGL Merger Order, the Commission approved the formation of AGL's system service company, AGL Services, and authorized certain intrasystem transactions. Applicants propose that NUI and the NUI Subsidiaries enter into a services agreement with AGL Services under the same form of services agreement in the AGL Merger Order.

A. AGL Services

Applicants state that AGL Services is a service company established in accordance with section 13(b) of the Act. AGL Services provides business services to AGL Resources and its subsidiaries including: rates and regulatory services, internal auditing, strategic planning, external affairs, gas supply and capacity management, legal services and risk management, marketing, financial services, information systems and technology, corporate services, investor relations, customer services, purchasing, employee services, engineering, business support, facilities management and other services, such as business development, that may be agreed upon by the subsidiaries and AGL Services. As compensation for services, the services agreement between the subsidiaries and AGL Services provides for client companies to pay to AGL Services the cost of these services, computed in accordance with the applicable rules and regulations under the Act and appropriate accounting standards.

Applicants propose that AGL Services provide business services to NUI and the NUI Subsidiaries under the same terms and conditions as AGL Services serves the companies currently within the AGL Resources registered holding company system, as approved by the Commission.

B. Gas Procurement and Asset Management Arrangement

NUI Utilities also proposes to enter into a three year gas procurement and asset management arrangement with a subsidiary of AGL Resources, Sequent Energy Management ("Sequent"). Sequent provides gas procurement and transportation and storage capacity asset management services to AGLC, VNG and CGC under arrangements with the respective state commissions with jurisdiction over AGLC, VNG and CGC.[7] Under these arrangements, Sequent provides commodity gas, including related procurement services, and also acts as agent for AGLC, VNG and CGC in connection with transactions for gas transportation and storage capacity. Sequent proposes to provide similar services to NUI Utilities and VGDC subject to the approval of the NJBPU and the VSCC.

The asset management model that Sequent employs provides for revenue sharing between the asset manager and AGLC, VNG and CGC's ratepayers. Applicants state that under its current arrangements with AGLC, VNG and CGC, Sequent contributed approximately $9.9 million to customers in 2003.

C. Billing Services

NUI Utilities currently has an Agreement for Billing Services, dated February 18, 2004, with UBS under which UBS provides NUI Utilities with certain billing related services using NUI Utilities' customer information system and certain other data center services on UBS' mainframe computer, including operating systems related to NUI Utilities' work order management, leak management, meter management, time entry and field services. The agreement is effective until March 31, 2007, but may be terminated by NUI Utilities with 180 days prior written notice. This agreement has been approved by the NJBPU.

Applicants state that UBS charges NUI Utilities market rates for the provision of these services, however, after closing, AGL Resources proposes to cause UBS and NUI Utilities to amend the agreement to require the services to be provided to NUI Utilities at UBS' cost. Prior to implementing such amendment, however, AGL Resources must determine whether a change in the pricing standard to terms more favorable to NUI Utilities would trigger contractual obligations to provide cost-based pricing to UBS' unaffiliated customers. In addition, if NJBPU approval of the amended contract is required, AGL Resources must seek this authorization before restructuring the contract between UBS and NUI Utilities. As a result, AGL Resources requests a temporary exception to the "at cost" provisions of section 13(b) of the Act and the applicable rules for two years to provide adequate time to restructure this contract. Applicants state that it is possible that at the end of the two-year period AGL Resources will be able to restructure all of UBS' existing contracts so that it may consolidate UBS with NUI Utilities.

D. Construction and Management Services

VGC provides construction and operations management services to SSLLC through its wholly owned subsidiary, Virginia Gas Pipeline Company ("VGPC"). Applicants state that VGPC serves as the construction and operations manager to SSLLC, under an agreement ("Operating Agreement"), dated August 15, 2001. Under the terms of the Operating Agreement, SSLLC reimburses VGPC for the costs it incurs to construct, maintain and operate SSLLC's facilities, including VGPC's administration and labor costs.

IV. Rule 16 Exemption

SSLLC, a 50% joint venture between NUI Saltville Storage and Duke Energy Gas Transmission, is developing a natural gas storage facility in Saltville, Virginia. SSLLC will not have more than 50% of its voting securities controlled by a registered holding company. Applicants assert that SSLLC is entitled to an exemption from the obligations, duties and liabilities imposed upon it under rule 16 under the Act as a subsidiary or affiliate of a registered holding company. Applicants request that the Commission authorize AGL Resources to acquire NUI's interest in SSLLC under sections 9(a)(1) and 10. The exemption under rule 16 will permit SSLLC to continue to operate in accordance with its usual practice without the need for additional authorization under the Act.

V. Tax Allocation Agreement

By order dated December 23, 2003 (HCAR No. 27781), the Commission authorized AGL Resources' tax allocation agreement. AGL Resources proposes to add NUI and the NUI Subsidiaries to the existing tax allocation arrangements for the AGL Resources system.

VI. Section 3(a)(1) Exemption Request for VGC

Applicants state that VGC and its only utility subsidiary, VGDC, carry on their utility operations exclusively within Virginia where each company is incorporated. Applicants state that after the Merger, VGC and VGDC, will remain predominantly intrastate in character and carry on their business substantially within Virginia. Applicants request that the Commission issue an order under section 3(a)(1) of the Act providing that VGC and each of its subsidiary companies, will be exempt from all provisions of the Act, except section 9(a)(2). VGC will remain jurisdictional as a subsidiary of a registered holding company. Applicants state that the VSCC will continue to have jurisdiction and authority over all of VGDC's rates, services and operations following the acquisition.

VII. Financing Authority

Applicants request authority for NUI and the NUI Subsidiaries, after the consummation of the Merger, to engage in the various financing transactions described below through March 31, 2007 ("Authorization Period"). Applicants state that financings by NUI and the NUI Subsidiaries will be subject to the following limitations ("Financing Limitations"):

A. Financing Limitations

1. Use of Proceeds

Applicants state that the proceeds from the sale of securities in these financing transactions will be used for general corporate purposes, including the financing, in part, of the capital expenditures and working capital requirements of NUI and its subsidiaries, for the acquisition, retirement or redemption of securities previously issued by NUI or the NUI Subsidiaries, and for authorized investments in companies organized in accordance with rule 58 under the Act, and for other lawful purposes.

2. Maturity

The maturity of long-term debt will be between one and 50 years. Short-term debt will mature within one year.

3. Common Equity Ratio

NUI Utilities and VGDC, on an individual basis, will maintain common stock equity of at least 30% of total capitalization as shown in its most recent quarterly balance sheet.

B. NUI Securities

NUI requests authorization to issue and sell debt and equity securities to AGL Resources and/or AGL Resources' financing subsidiaries as necessary to finance the authorized and permitted businesses of NUI and the NUI Subsidiaries. In particular, NUI requests authorization to issue intercompany notes to AGL Resources or AGL Resources' financing subsidiaries in connection with the refinancing of NUI's pre-Merger indebtedness. Applicants state that at the close of the Merger, NUI's existing credit facilities, under which it has approximately $275 million outstanding, will terminate and the outstanding amounts will become due. NUI states that intercompany notes would be issued by NUI in an amount at any one time outstanding of up to $285million, which amount will refinance NUI's pre-Merger indebtedness.[8] Applicants state that the intercompany note will have a 30-year term and can be repaid at anytime by NUI prior to its maturity. Applicants state that the length of term of the note is consistent with the character of NUI's assets; provides it with an adequate capital structure and appropriate liquidity and otherwise maintains its ability to meet its other obligations. NUI states that it would not issue debt or equity securities to third-party, unaffiliated entities post-Merger without seeking subsequent Commission authorization. NUI also requests authorization to acquire the securities of its direct and indirect subsidiaries and to extend credit to these subsidiaries for purposes of financing these companies' authorized and permitted businesses in an aggregate amount outstanding during the Authorization Period not to exceed $300 million.

C. NUI Utilities and VGDC Debt Securities

Applicants request authorization for NUI Utilities and VGDC to (a) enter into, perform, purchase and sell Hedging Instruments; (b) to issue short-term debt consisting of unsecured borrowings under the utility money pool ("Utility Money Pool"), at any one time outstanding during the Authorization Period subject to the Utility Short-Term Debt Limit defined below.

In this Application, Applicants request authorization for NUI Utilities and VGDC to make up to $600 million and $250 million, respectively, of borrowings under the Utility Money Pool ("Utility Short-Term Debt Limit"). This level of short term financing authorization is necessary to assure that NUI Utilities and VGDC have adequate working capital to finance the acquisition of gas supply, particularly in the current high-cost gas market.

NUI Utilities also requests authorization to issue intercompany notes to AGL Resources or a financing subsidiary thereof in connection with the refinancing of NUI Utilities' pre-Merger indebtedness. Intercompany notes would be issued by NUI Utilities in an amount at any one time outstanding of up to $275 million, respectively. (The intercompany notes issued by NUI Utilities would be for terms longer than one year and accordingly such issuances would not count against the $600 million short-term debt limit stated above.) At the time of closing, NUI Utilities will have approximately $260 million of pre-Merger debt outstanding. This indebtedness is made up of $150 million of unsecured indebtedness under an existing credit facility, which terminates at closing; $75 million of secured indebtedness under a seasonal credit facility (which terminates at closing); approximately $30MM of settlement payments to ratepayers pursuant to settlement agreements with various state regulatory agencies (which becomes due at or around closing). At closing, NUI Utilities will also have $200 million of indebtedness to third parties under its existing revenue bonds, which will remain outstanding after closing. AGL Resources is evaluating the economics of refinancing an additional amount of debt issued by NUI Utilities in the amount of approximately $200 million. The refinancing of this amount, if consummated, and the post-Merger financing of NUI Utilities with securities other than short-term debt would be conducted on an exempt basis under Rule 52(a) through the sale of securities by NUI Utilities, pursuant to NJBPU authorization, externally to third parties or on an intercompany basis. The intercompany note will have a 30-year term and can be repaid at anytime by NUI Utilities prior to its maturity. The long term of the note is consistent with the character of NUI Utilities' assets; provides it with an adequate capital structure and appropriate liquidity and otherwise maintains its ability to meet its other obligations

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VIII. NUI Utilities' Intercompany Note

NUI Utilities requests authorization to issue intercompany notes to AGL Resources or a financing subsidiary of AGL Resources in connection with the refinancing of NUI Utilities pre-Merger indebtedness.[9] Applicants state that NUI Utilities would issue intercompany notes in an amount at any one time outstanding of up to $275 million. Applicants request that the intercompany notes issued by NUI Utilities be for terms longer than one year and accordingly the intercompany note would not count against the NUI Utilities' Short-Term Debt stated above. Applicants state that, at the time of closing, NUI Utilities will have approximately $260 million of pre-Merger debt outstanding. This indebtedness is made up of $150 million of unsecured indebtedness under an existing credit facility, which terminates at closing; $75 million of secured indebtedness under a seasonal credit facility (which terminates at closing); approximately $35 million of settlement payments to ratepayers under settlement agreements with various state regulatory agencies (which becomes due at or around closing). At closing, NUI Utilities will also have $200 million of indebtedness to third parties under its existing revenue bonds, which will remain outstanding after closing. AGL Resources states that it is evaluating the economics of refinancing an additional amount of debt issued by NUI Utilities in the amount of approximately $200 million. Applicants state that the refinancing of this amount, if consummated, and the post-Merger financing of NUI Utilities with securities other than short-term debt would be conducted on an exempt basis under rule 52(a) through the sale of securities by NUI Utilities, under NJBPU authorization, externally to third parties or on an intercompany basis. Applicants state that the intercompany note will have a 30-year term and can be repaid at anytime by NUI Utilities prior to its maturity. Applicants state that the length of the term of the note is consistent with the character of NUI Utilities' assets; provides it with an adequate capital structure and appropriate liquidity and otherwise maintains its ability to meet its other obligations.

A. Authorization and Operation of the Money Pools

Applicants request authorization for NUI Utilities and VGDC to participate in AGL Resources' Utility Money Pool and to make unsecured short-term borrowings from the Utility Money Pool, to contribute surplus funds to the Utility Money Pool, lend and extend credit to, and acquire promissory notes from, one another through the Utility Money Pool subject to the Financing Limiations.

Specifically, Applicants state that the Utility Money Pool funds are available for short-term loans to the Utility Money Pool participants from time to time through: (i) surplus funds in the treasuries of participants and (ii) proceeds received by the Utility Money Pool participants from the sale of commercial paper and borrowings from banks ("External Funds"). Funds are made available from sources in the order that AGL Services, as the administrator under the Utility Money Pool Agreement, determines would result in a lower cost of borrowing compared to the cost that would be incurred by the borrowing participants individually in connection with external short-term borrowings, consistent with the individual borrowing needs and financial standing of Utility Money Pool participants that invest funds in the Utility Money Pool.

Each Utility Money Pool borrower ("Utility Borrower") which borrows through the Utility Money Pool will borrow pro rata from each Utility Money Pool participant that invests surplus funds, in the proportion that the total amount invested by the Utility Money Pool participant bears to the total amount then invested in the Utility Money Pool. The interest rate charged to Utility Borrowers on borrowings under the Utility Money Pool is equal to AGL Resources' actual cost of external short-term borrowings and the interest rate paid on loans to the Utility Money Pool is a weighted average of the interest rate earned on loans made by the Utility Money Pool and the return on excess funds earned from the investments described below. The interest income and investment income earned on loans and investments of surplus funds is allocated among those Utility Money Pool participants that have invested funds in accordance with the proportion each participant's investment of funds bears to the total amount of funds invested in the Utility Money Pool. Applicants state that borrowings through the Utility Money Pool by NUI Utilities would be limited to $600 million and borrowings by VGDC would be limited to $250 million at any one time outstanding.

Funds not required by the Utility Money Pool to make loans (with the exception of funds required to satisfy the Utility Money Pool's liquidity requirements) are ordinarily invested in one or more short-term investments, including: (i) obligations issued or guaranteed by the U.S. government and/or its agencies and instrumentalities; (ii) commercial paper; (iii) certificates of deposit; (iv) bankers' acceptances; (v) repurchase agreements; (vi) tax exempt notes; (vii) tax exempt bonds; (viii) tax exempt preferred stock and (ix) other investments that are permitted by section 9(c) of the Act and rule 40 under the Act.

Each Utility Borrower receiving a loan through the Utility Money Pool is required to repay the principal amount of the loan, together with all interest accrued, on demand and in any event within one year after the date of the loan. All loans made through the Utility Money Pool may be prepaid by the borrower without premium or penalty and without prior notice.

In the Financing Order, AGL Resources and the AGL Nonutility Subsidiaries were granted authorization to operate a nonutility money pool ("Nonutility Money Pool"), and the AGL Nonutility Subsidiaries were authorized to make unsecured short-term borrowings from the Nonutility Money Pool, to contribute surplus funds to the Nonutility Money Pool, and to lend and extend credit to, and to acquire promissory notes from, one another through the Nonutility Money Pool subject to the terms and conditions set forth in the Financing Order. Applicants request that, following the Merger, the NUI Nonutilities be authorized to participate in the Nonutility Money Pool under the same terms and conditions as the AGL Nonutility Subsidiaries.

AGL Resources and NUI would continue to contribute surplus funds and to lend and extend credit to the Utility Money Pool and the Nonutility Money Pool. AGL Resources and NUI will not borrow from either the Utility Money Pool or the Nonutility Money Pool. AGL Services will continue to serve as administrator for both the Utility Money Pool and the Nonutility Money Pool and will provide the administrative services at cost.

B. Guarantees

Applicants request authorization for AGL Resources to guarantee the obligations of NUI and the NUI Subsidiaries. In addition, Applicants request authority for NUI, NUI Utilities, VGC and VGDC to enter into guarantees, obtain letters of credit, enter into expense agreements or provide credit support with respect to obligations of their subsidiaries ("Guarantees") subject to the Financing Limitations in the amount of $150 million and $100 million with respect to NUI Utilities and VGDC, and in the amount of $300 million and $75 million with respect to NUI and VGC. These Guarantees may take the form of, among others, direct guarantees, reimbursement undertakings under letters of credit, "keep well" undertakings, agreements to indemnify, expense reimbursement agreements, and credit support with respect to the obligations of the subsidiary companies as may be appropriate to enable the system companies to carry on their respective authorized or permitted businesses. Applicants state that any Guarantee that is outstanding at the end of the Authorization Period will remain in force until it expires or terminates in accordance with its terms. Certain Guarantees may be in support of obligations that are not capable of exact quantification. In these cases, for purposes of measuring compliance with the appropriate Guarantee limit the exposure under a Guarantee would be determined by appropriate means, including estimation of exposure based on potential payment amounts. If appropriate, Applicants state that these estimates will be made in accordance with Generally Accepted Accounting Principles and this estimation will be reevaluated periodically. Applicants request that NUI and the NUI Subsidiaries be charged a fee for any Guarantee provided on its behalf that is not greater than the cost, if any, incurred by the guarantor in obtaining the liquidity necessary to perform the Guarantee for the period of time the Guarantee remains outstanding.

C. Hedges

Applicants request authorization for NUI Utilities, VGC and VGDC to enter into, perform, purchase and sell financial instruments intended to manage the volatility of interest rates, including but not limited to interest rate swaps, caps, floors, collars and forward agreements or any other similar agreements ("Hedging Instruments"). Hedging Instruments, in addition to the foregoing sentence, may also include the issuance of structured notes (i.e., a debt instrument in which the principal and/or interest payments are indirectly linked to the value of an underlying asset or index), or transactions involving the purchase or sale, including short sales, of U.S. Treasury or agency (e.g., Federal National Mortgage Association) obligations or London Inter-Bank Offer Rate-based swap instruments. These companies would employ Hedging Instruments only as a means of prudently managing the risk associated with any of its outstanding debt issued on an exempt basis under Rule 52 by, in effect, synthetically (i) converting variable-rate debt to fixed-rate debt; (ii) converting fixed rate debt to variable rate debt; (iii) limiting the impact of changes in interest rates resulting from variable-rate debt; and (iv) providing an option to enter into interest rate swap transactions in future periods for planned issuances of debt securities. In no case will the notional principal amount of any Hedging Instrument exceed that of the underlying debt instrument and related interest rate exposure. Thus, these companies will not engage in "leveraged" or "speculative" transactions. The underlying interest rate indices of such Hedging Instrument will closely correspond to the underlying interest rate indices of the companies' debt to which such Hedging Instrument relates. Off-exchange Hedging Instruments would be entered into only with counterparties whose senior debt ratings are investment grade as determined by any one of Standard & Poor's, Moody's Investors Service, Inc. or Fitch IBCA, Inc. ("Approved Counterparties").

In addition, Applicants request authorization for NUI Utilities, VGC and VGDC to enter into Hedging Instruments with respect to anticipated debt offerings ("Anticipatory Hedges"), subject to certain limitations and restrictions and only in connection with debt issued on an exempt basis under Rule 52. Anticipatory Hedges would only be entered into with Approved Counterparties, and would be used to fix and/or limit the interest rate risk associated with any new issuance through (i) a forward sale of exchange-traded Hedging Instruments ("Forward Sale"); (ii) the purchase of put options on Hedging Instruments ("Put Options Purchase"); (iii) a Put Options Purchase in combination with the sale of call options on Hedging Instruments ("Zero Cost Collar"); (iv) transactions involving the purchase or sale, including short sales, of Hedging Instruments; or (v) some combination of a Forward Sale, Put Options Purchase, Zero Cost Collar and/or other derivative or cash transactions, including, but not limited to structured notes, caps and collars, appropriate for the Anticipatory Hedges.

Hedging Instruments may be executed on-exchange ("On-Exchange Trades") with brokers through the opening of futures and/or options positions traded on the Chicago Board of Trade, the opening of over-the-counter positions with one or more counterparties ("Off-Exchange Trades"), or a combination of On-Exchange Trades and Off-Exchange Trades. The companies will determine the optimal structure of each Hedging Instrument transaction at the time of execution.

Applicants state that they will comply with Statement of Financial Accounting Standards ("SFAS") 133 ("Accounting for Derivative Instruments and Hedging Activities"), SFAS 138 ("Accounting for Certain Derivative Instruments and Certain Hedging Activities") or other standards relating to accounting for derivative transactions as are adopted and implemented by the Financial Accounting Standards Board ("FASB"). Applicants state that Hedging Instruments will qualify for hedge accounting treatment under the current FASB standards in effect and as determined at the date Hedging Instruments are entered into.

D. Changes in Capital Stock of Wholly-Owned Subsidiaries

Applicants request authorization to change the terms of the authorized capital stock of NUI and any wholly owned subsidiary of NUI authorized capital stock by an amount deemed appropriate by AGL Resources or other intermediate parent company subject to the following conditions. A wholly owned subsidiary will be able to change the par value, or change between par value and no-par stock, without additional Commission approval. Any action by NUI Utilities or VGDC would be subject to and would only be taken upon the receipt of any necessary approvals by the state commission in the state or states where the utility subsidiary is incorporated and doing business. In addition, NUI Utilities and VGDC will maintain, during the Authorization Period, a common equity capitalization of at least 30%.

E. Payment of Dividends Out of Capital or Unearned Surplus

Applicants request authorization for NUI and the NUI Nonutilities to pay dividends from time to time through the Authorization Period, out of capital and unearned surplus. Applicants state that NUI and the NUI Nonutilities will not declare or pay any dividend out of capital or unearned surplus unless it: (i) has received excess cash as a result of the sale of some or all of its assets; (ii) has engaged in a restructuring or reorganization and/or (iii) is returning capital to an associate company. In addition, NUI or an NUI Nonutility would only declare or pay dividends to the extent permitted under applicable corporate law and state or national law applicable in the jurisdiction where each company is organized, and any applicable financing covenants.

Applicants request that the Commission reserve jurisdiction over NUI Utilities' payment of dividends out of capital and unearned surplus in an amount up to its pre-merger retained earnings.

Applicants represent that NUI Utilities will not declare or pay any dividend out of capital or unearned surplus in contravention of any law restricting the payment of dividends. NUI Utilities also will comply with the terms of any credit agreements and indentures that restrict the amount and timing of distributions to shareholders. NUI Utilities would not pay dividends out of capital or unearned surplus if to do so would cause its equity to decline to less than 30% of total capitalization.

IX. Intermediate Subsidiaries

Applicants request authorization for NUI to acquire, directly or indirectly, the securities of one or more entities ("Intermediate Subsidiaries"), which would be organized exclusively for the purpose of acquiring, holding and/or financing the acquisition of the securities of or other interest in one or more exempt wholesale generators, as that term is defined in section 32 of the Act ("EWGs"), foreign utility companies as that term is defined in section 33 of the Act ("FUCOs"), companies exempt under rule 58 ("Rule 58 Companies"), exempt telecommunications companies, as that term is defined under section 34 of the Act, ("ETCs") or other non-exempt nonutility subsidiaries. These Intermediate Subsidiaries may also engage in certain administrative activities ("Administrative Activities") and development activities ("Development Activities").

Administrative Activities include ongoing personnel, accounting, engineering, legal, financial and other support activities necessary to manage investments in nonutility subsidiaries. Development Activities are limited to due diligence and design review; market studies; preliminary engineering; site inspection; preparation of bid proposals, including, in connection therewith, posting of bid bonds; application for required permits and/or regulatory approvals; acquisition of site options and options on other necessary rights; negotiation and execution of contractual commitments with owners of existing facilities, equipment vendors, construction firms, and other project contractors; negotiation of financing commitments with lenders and other third-party investors; and other preliminary activities that may be required in connection with the purchase, acquisition, financing or construction of facilities, or the acquisition of securities of or interests in new businesses.

An Intermediate Subsidiary may be organized, among other things: (i) to facilitate the making of bids or proposals to develop or acquire an interest in any EWG, FUCO, Rule 58 Company, ETC or other nonutility subsidiary; (ii) after the award of a bid proposal, to facilitate closing on the purchase or financing of an acquired company; (iii) at any time subsequent to the consummation of an acquisition of an interest in any such company to, among other things, effect an adjustment in the respective ownership interests in such business held by NUI and non-affiliated investors; (iv) to facilitate the sale of ownership interests in one or more acquired non-utility companies; (v) to comply with applicable laws of foreign jurisdictions limiting or otherwise relating to the ownership of domestic companies by foreign nationals; (vi) as a part of tax planning in order to limit NUI's exposure to taxes; (vii) to further insulate NUI, NUI Utilities and VGDC from operational or other business risks that may be associated with investments in non-utility companies or (viii) for other lawful business purposes.

Investments in Intermediate Subsidiaries may take the form of any combination of the following: (i) purchases of capital shares, partnership interests, member interests in limited liability companies, trust certificates or other forms of equity interests; (ii) capital contributions; (iii) open account advances with or without interest; (iv) loans and (v) guarantees issued, provided or arranged in respect of the securities or other obligations of any Intermediate Subsidiaries. Funds for any direct or indirect investment in any Intermediate Subsidiary will be derived from: (i) financings authorized in this proceeding; (ii) any appropriate future debt or equity securities issuance authorization obtained by NUI from the Commission and (iii) other available cash resources, including proceeds of securities sales by the NUI Nonutilities under rule 52. To the extent that NUI provides funds or Guarantees directly or indirectly to an Intermediate Subsidiary that are used for the purpose of making an investment in any EWG, FUCO or Rule 58 Company, the amount of the funds or Guarantees are included in NUI's "aggregate investment" in these entities, as calculated in accordance with rule 53 or rule 58, as applicable. AGL Resources requests that its authorization, in the Financing Order, to make expenditures on Development Activities, as defined above, in an aggregate amount of up to $600 million be extended to include the NUI Nonutilities.

Applicants state that neither AGL Resources nor any of its subsidiaries presently has an interest in any EWG or FUCO.

X. Reorganization

AGL Resources and NUI request authorization to consolidate or otherwise reorganize all or any part of its direct and indirect ownership interests in the NUI Nonutilities, and the activities and functions related to these investments. To effect any consolidation or other reorganization, AGL Resources or NUI may wish to merge or contribute the equity securities of one NUI Nonutility to another NUI Nonutility (including a newly formed Intermediate Subsidiary) or sell (or cause a nonutility subsidiary to sell) the equity securities or all or part of the assets of one nonutility subsidiary to another one. To the extent that these transactions are not otherwise exempt under the Act or or applicable rules, AGL Resources and NUI request authorization to consolidate or otherwise reorganize under one or more direct or indirect Intermediate Subsidiaries, their ownership interests in existing and future NUI Nonutility. These transactions may take the form of a nonutility subsidiary selling, contributing, or transferring the equity securities of a subsidiary or all or part of a subsidiary's assets as a dividend to an Intermediate Subsidiary or to another nonutility subsidiary, and the acquisition, directly or indirectly, of the equity securities or assets of the subsidiary, either by purchase or by receipt of a dividend. The purchasing nonutility subsidiary in any transaction structured as an intrasystem sale of equity securities or assets may execute and deliver its promissory note evidencing all or a portion of the consideration given. Each transaction will be carried out in compliance with all applicable laws and accounting requirements.

XI. Retention of Nonutility Subsidiaries

Applicants state that Exhibit J-1 to the Application and attached as an appendix to this order describes AGL Resources' current plans for retaining or divesting each of the NUI Nonutilities and discusses the legal basis for retention where applicable. Applicants state that numerous NUI Nonutilities will be wound down, liquidated or dissolved. AGL Resources will endeavor to wind down, liquidate or dissolve these investments by December 31, 2007, giving due regard for the need to insulate the rest of the AGL Resources group from any liabilities or obligations that may be associated with these companies. Applicants state that, to the extent any entity listed in Exhibit J-1 is not wound down, liquidated or dissolved by December 31, 2007, AGL Resources will request authority through a post effective amendment to this application to continue to retain the entities as necessary.

In addition, AGL Resources seeks authorization to retain UBS and for UBS to continue to provide services to NUI Utilities under its current arrangement not to exceed two years after the date of the order authorizing this acquisition. Specifically, AGL Resources intends to maintain the existing services arrangements between UBS and NUI Utilities for two years after the date of the SEC's order granting this Application. During that time, AGL Resources will endeavor to either restructure the existing UBS services agreements with NUI Utilities so that services thereunder may be provided at cost (provided that such modification is practicable given UBS' other contractual arrangements), or would otherwise endeavor to consolidate the applicable portions of UBS's current operations into NUI Utilities. If necessary, at the end of the two year period, AGL Resources will submit a post effective amendment to this application seeking to extend this authorization.

Applicants state that UBS' operating revenues and operating margins were $6.1 million and $3.6 million, respectively, in fiscal year 2003. UBS provides customer information systems and services to investor-owned and municipal utilities, as well as third party providers in the water, wastewater and gas markets. A customer information system developed and maintained by USB is presently serving 13 clients in support of more than 1.5 million customers. UBS provides billing and payment processing services to NUI Utilities under a service agreement approved by the NJBPU. Applicants state that in June 2003 NUI approved a plan to sell UBS. However, the September 2003 decision to sell NUI reduced the probability that a sale of UBS would occur, given that there was no guarantee that UBS' largest customer, NUI Utilities, would maintain a long-term relationship with UBS after the sale. After the acquisition, Applicants expect that the activities of UBS would be folded into NUI Utilities or replaced.

XII. NUI Reporting

NUI will register as a holding company under the Act by filing a Notification of Registration on Form U5A upon the consummation of the Merger. Thereafter NUI will join AGL Resources in the filing of a joint Annual Report on Form U5S on or before May 1, 2005 and annually thereafter. NUI requests that the Commission find under Section 5(b) and Rule 20(a)(3) that the joint AGL Resources - NUI Annual Report on Form U5S filed on or before May 1, 2005 may also serve as NUI's Registration Statement on Form U5B, given that both the Annual Report and the Registration Statement would cover NUI's position at the close of the year 2004 and contain substantially equivalent information about NUI's subsidiaries, investments, financings, directors, affiliate transactions, and other matters. It would be duplicative to cause NUI to file a separate Registration Statement on Form U5B within 90 days of the Merger and NUI's registration under the Act, and then cause NUI to provide largely similar information only a few months later in the joint Annual Report on Form U5S. As required by Item 10 of Form U5S, the joint Annual Report on Form U5S would include consolidating financial statements for AGL Resources and each of its subsidiary companies, including NUI and its subsidiaries. In addition, Applicants will commit to provide as a supplement to the Form U5S submission any information required by Form U5B that the Commission staff deems necessary or appropriate for the combined filing.

XIII. Discussion

The proposed transactions requires the Commissions prior approval under sections 3(a)(1), 5, 6(a), 7, 9(a), 10, 11, 12(b), 12(c) and 13(b) of the Act and rules 16, 43, 45, 46, 54, 88, 90 and 91 under the Act. We have reviewed the proposed transactions and find that the requirements of the Act are satisfied. The effect of the Merger on AGL Resources and the benefits of the Merger to NUI are discussed below.

The Commission may not approve the Merger if it determines, under Section 10(b)(3), that the acquisition will unduly complicate the capital structure of AGL Resources or will be detrimental to the public interest or the interest of investors or consumers or the proper functioning of the holding-company system. Applicants assert that, for the reasons given below, there is no basis for the Commission to make either of these negative findings concerning the Merger.

The capital structure of AGL Resources after the transaction will not be unduly complicated and will be substantially unchanged from AGL Resources' capital structure prior to the completion of the transaction. The proposed acquisition is of manageable size and hence credit neutral to AGL Resources. NUI will represent approximately 20% of the combined company. AGL Resources can finance this acquisition without significant pressure on its balance sheet or credit rating. Applicants note that the transaction is limited in scope and should strengthen AGL Resources' financial performance in the near term. NUI's current financial difficulties have arisen from issues related to mismanagement of utility assets, including unsuccessfully executed diversification strategies; downgrades in NUI and NUI Utilities' credit ratings; the related high cost debt and gas commodity purchases and subsequent regulatory audits, investigations and in some cases criminal indictments. Regardless of these difficulties, NUI's utility businesses are fundamentally sound. Applicants state that the nonutility businesses that gave rise to NUI's financial difficulties have been wound down and will soon be divested or closed. Further, NUI, and eventually AGL Resources, will continue implementing procedures that will address NUI's prior mismanagement of accounts and controls and internal audit issues.

The pro forma capitalization further demonstrates that the combination would not result in a complex or unsound capital structure. In this regard, the Commission is concerned that there be an adequate level of equity in the top level holding company and each utility in the system. The combined entity will have in excess of 42% common equity as a percentage of total capitalization, well in excess of the Commission's traditional minimum 30% common equity standard.[10]

XIV. Rule 24 Certificates

NUI states that it will register as a holding company under the Act by filing a Notification of Registration on Form U5A upon the consummation of the Merger. NUI will join AGL Resources in the filing of a joint Annual Report on Form U5S on or before May 1, 2005 and annually thereafter. NUI requests that the Commission find under section 5(b) and rule 20(a)(3) that the joint AGL Resources - NUI Annual Report on Form U5S filed on or before May 1, 2005 may also serve as NUI's Registration Statement on Form U5B. As required by Item 10 of Form U5S, the joint Annual Report on Form U5S will include consolidating financial statements for AGL Resources and each of its subsidiary companies, including NUI and the NUI Subsidiaries after the Merger. In addition, Applicants commit to provide as a supplement to the Form U5S submission any information required by Form U5B that the Commission staff deems necessary or appropriate for the combined filing.

AGL Resources also proposes to integrate the NUI and the NUI Subsidiaries into the quarterly reports it files according to the Financing Order.

Beginning with the rule 24 certificate that is due to be filed in the Financing Order 60 days after the end of the calendar quarter in which the Merger is consummated, AGL Resources' rule 24 certificates will also include the information specified below with respect to NUI and the NUI Subsidiaries.

1. If sales of common stock by AGL Resources are reported, the purchase price per share and the market price per share at the date of the agreement of sale and the aggregate amount of common stock outstanding during the Authorization Period;

2. The total number of shares of AGL Resources' common stock issued or issuable pursuant to options granted during the quarter under employee benefit plans and dividend reinvestment plans including any employee benefit plans or dividend reinvestment plans hereafter adopted and the total number of shares of AGL Resources' common stock issued or issuable pursuant to options outstanding during the Authorization Period;

3. If AGL Resources' common stock has been transferred to a seller of securities of a company being acquired, the number of shares so issued, the value per share and whether the shares are restricted in the hands of the acquirer;

4. If a guarantee is issued during the quarter, the name of the guarantor, the name of the beneficiary of the guarantee and the amount, terms and purpose of the guarantee, and the total amount of guarantees issued and outstanding during the Authorization Period;

5. The amount and terms of any financings consummated by AGLC,

CGC, VNG, NUI Utilities or VGDC that are not exempt under rule 52, and the total amount of such financings outstanding of each of AGLC, CGC, VNG, NUI Utilities and VGDC during the Authorization Period;

6. If any of AGL Resources' subsidiaries (including the NUI Group companies) are Variable Interest Entities ("VIEs") as that term is used in FASB Interpretation 46R, Consolidation of Variable Interest Entities, provide a description of any financing transactions conducted during the reporting period that were used to fund such VIEs;
7. If any financing proceeds are used for VIEs, a description of the accounting for such transaction under FASB Interpretation 46R;
8. A list of U-6B-2 forms filed with the Commission during the quarter, including the name of the filing entity and the date of filing;
9. Consolidated balance sheets as of the end of the quarter and separate balance sheets as of the end of the quarter for each company, including AGL Resources, that has engaged in utility money pool transactions during the quarter;
10. Future registration statements filed under the 1933 Act with respect to securities issuances that are the subject of the Application will be filed or incorporated by reference as exhibits to the next certificate filed pursuant to rule 24;
11. A table showing, as of the end of the quarter, the dollar and percentage components of the capital structure of AGL Resources on a consolidated basis, and each of AGLC, CGC, VNG, NUI Utilities and VGDC;
12. A retained earnings analysis of AGL Resources on a consolidated basis and for each of AGLC, CGC, VNG, NUI Utilities and VGDC detailing gross earnings, goodwill amortization, dividends paid out of capital surplus, and the resulting capital account balances at the end of the quarter;
13. Certain financial information regarding AGLC, CGC, VNG, VGDC, NUI Utilities, Elizabethtown Gas, Elkton Gas and City Gas as follows: revenues, cost of goods sold, operating income, interest, taxes, amortization, net income, fixed assets, current assets and total assets and
14. AGL Resources will report on the progress of winding down and dissolving, merging or selling certain NUI Nonutility Subsidiaries identified in Exhibit J-1 of this Application.

XV. Rule 54 Analysis

Applicants state that neither AGL Resources nor any of its subsidiaries presently has or will have after the consummation of the Merger an interest in any EWG or FUCO.

XVI. Fees and Jurisdiction

Applicants state that fees and commissions associated with the completion of the transaction amount to $23.6 million. Applicants state that the states of New Jersey, Florida, Maryland and Virginia have jurisdiction over and have approved the transaction. Applicants further state that New Jersey approved the transaction on November 9, 2004, Maryland approved the transaction on October 27, 2004 and Virginia approved the transaction on October 29, 2004. In addition, Applicants state that the transaction falls under the jurisdiction of the FTC and the DOJ under the HSR Act. Applicants state that on August 5, 2004, the parties filed their notification and report forms under the HSR Act with the FTC and the Antitrust Division of the DOJ and the waiting period terminated on September 7, 2004. Applicants further state that the transaction falls under the jurisdiction of the Federal Communications Commission because NUI and the NUI Subsidiaries own communications licenses which are jurisdictional under the Communications Act of 1934. Applicants state that on October 27, 2004, the FCC issued public notice of its grant of the transfer of control applications.

Due notice of the filing of this Application, as amended, has been given in the manner prescribed in rule 23 under the Act, and no hearing has been requested of, or ordered by, the Commission. On the basis of the facts in the record, it is found that, except as to those matters over which jurisdiction has been reserved, the applicable standards of the Act and rules under the Act are satisfied, and that no adverse findings are necessary.

IT IS ORDERED, under the applicable provisions of the Act and rules under the Act, that, except as to those matters over which jurisdiction has been reserved, the Application, as amended, be granted and permitted to become effective immediately, subject to the terms and conditions prescribed in rule 24 under the Act.

IT IS FURTHER ORDERED that jurisdiction be reserved over NUI Utilities' payment of dividends out of capital and unearned surplus in an amount up to its pre-merger retained earnings and out of post-merger earnings pending the completion of the record.

For the Commission by the Division of Investment Management, pursuant to delegated authority.

Margaret H. McFarland
Deputy Secretary

See Appendix

Endnotes

[1] See Appendix to this order.

[2] Applicants state that this figure is net of $111 million of cash at June 30, 2004.

[3] Applicants state that this figure is net of $66 million of cash at June 30, 2004.

[4] Applicants state that this figure includes current maturities of long-term debt. Applicants further state that this figure is net of $1 million of cash at June 30, 2004.

[5] Applicants state that Cougar Corporation is a wholly owned subsidiary of AGL Resources organized under the laws of New Jersey that was incorporated on July 14, 2004 solely for the purposes of the Merger and is engaged in no other business.

[6] These approvals are discussed in detail in section XIV of this order. Applicants state that NUI Utilities' City Gas division is subject to the jurisdiction of the Florida Public Service Commission ("FPSC"). Applicants further state that, subject to the plenary jurisdiction of the FPSC over the operations of NUI, no filing or approval of the merger by the FPSC is required by Florida law. However, within ten days of the consummation of the Merger, AGL Resources is required to file a notice with the FPSC stating that the tariffs then charged by City Gas of Florida will continue to remain in effect. Applicants state that AGL Resources will make this filing after consummation of the Merger.

[7] Applicants assert that these transactions are exempt from regulation under section 13(b) of the Act by virtue of rules 80 and 81.

[8] Applicants state that the rate of interest on the intercompany note(s) between AGL Resources (or its financing subsidiary AGL Capital Corporation ("AGLCC")) and NUI will be based upon the weighted-average cost of capital then outstanding for AGL Resources, excluding the cost of capital related to the currently outstanding medium-term notes that were issued by AGL Resources' utility subsidiary, AGLC prior to the formation of AGL Resources and the existing holding company structure. AGL Resources states that it recalculates the weighted-average cost of capital due as interest on each inter-company note each quarter based on the capital outstanding, and adjusts the amount of interest paid by its borrowing subsidiaries. Applicants further state that AGL Resources calculates the weighted average interest rate and expenses of AGL Resources' then outstanding debt, net of AGLC's outstanding medium-term notes, in order to determine the appropriate rate to charge to the borrower at the time the debt is incurred.

[9] Applicants state that the rate of interest on the intercompany note(s) between AGL Resources (or its financing subsidiary AGLCC) and NUI Utilities will be based upon the weighted-average cost of capital then outstanding for AGL Resources, excluding the cost of capital related to the currently outstanding medium-term notes that were issued by AGLC prior to the formation of AGL Resources and the existing holding company structure. AGL Resources states that it recalculates the weighted average cost of capital due as interest on each inter-company note each quarter based on the capital outstanding, and adjusts the amount of interest paid by its borrowing subsidiaries. In other words, AGL Resources calculates the weighted average interest rate and expenses of AGL Resources' then outstanding debt, net of AGLC's outstanding medium-term notes, in order to determine the appropriate rate to charge to the borrower at the time the debt is incurred.

[10] "Capitalization" for purposes of this test is the sum of short-term debt (including current maturities of long-term debt), long-term debt, preferred stock and common stock equity.

http://www.sec.gov/divisions/investment/opur/filing/35-27917.htm

14

Sales and Use Tax Exemption for Purchases of Energy by Public Utility Companies

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The following is the 2006 list of the public utility companies that are entitled to the sales and use tax exemption at N.J.S.A. 54:32B-8.47(a), which exempts: Utility corporations or persons that were subject to the provisions of N.J.S.A. 54:30A-16 as of 4-1-97 or were formerly or are currently subject to the provisions of N.J.S.A. 54:30A-49 et seq., for their own use & consumption.

Public Utility Energy Companies (Electricity and/or Natural Gas)
Formerly Subject to P.L.1940, c.5 (*N.J.S.A.* 54:30A-49 et seq.)

Atlantic City Electric Company (Electricity)
Butler Borough Municipal Electric Utility (Electricity)
(2) Elizabethtown Gas Co. (Pivotal Utility Holdings, Inc.) (Natural Gas)
Jersey Central Power and Light Company (Electricity)
New Jersey Natural Gas Company (Natural Gas)
Public Service Electric & Gas Company (Electricity and Natural Gas)
Rockland Electric Company (Electricity)
South Jersey Gas Company (Natural Gas)
Sussex Rural Electric Cooperative (Electricity)

Telephone Companies
Formerly Subject to P.L.1940, c.4 (*N.J.S.A.* 54:30A-16 et seq.) as April 1, 1997

United Telephone Company of New Jersey
Verizon New Jersey, Inc. (formerly Bell Atlantic-New Jersey, Inc.)
Warwick Valley Telephone Company

Sewer Companies
Currently Subject to P.L.1940, c.5 (*N.J.S.A.* 54:30A-49 et seq.)

Andover Utility Company, Inc. (Sewer)
Applied Wastewater Management, Inc. (Sewer Division)
(1) Aqua New Jersey, Inc. (Sewer Division)
Atlantic City Sewerage Company
Crestwood Village Sewer Company
Environmental Disposal Corporation (Sewer)
Montague Sewer Company
Mount Olive Villages Sewer Company, Inc.
New Jersey-American Water Company, Inc. (Sewer Division)
Oakwood Village Sewerage Associates, L.L.C.
Pinelands Wastewater Company (Sewer)
S.B. Sewer Company, Inc.
United Water Arlington Hills Sewerage, Inc.
United Water Great Gorge, Inc. (Sewer)
United Water Princeton Meadows, Inc. (Sewer)
United Water Vernon Sewage, Inc.
United Water West Milford, Inc. (Sewer)
Valley Road Sewerage Co.
Wallkill Sewer Company

Water Companies
Currently Subject to P.L.1940, c.5 (*N.J.S.A.* 54:30A-49 et seq.)

Applied Wastewater Management, Inc. (Water Division)

BAC000012

(1) (3) Aqua New Jersey, Inc. (Water Division)
Brookwood Musconetcong River Property Owners Assoc. (Water)
Byram Homeowners Association Water Company, Inc.
Cedar Glen Lakes Water Company
Cedar Glen West, Inc. (Water)
Crestwood Village Water Company
East Brookwood Estates Property Owners' Association, Inc (Water)
Fayson Lake Water Company
Forest Lakes Water Company
Gordon's Corner Water Company
Harkers Hollow Heights Water Association
Lake Lenape Water Company
Lake Stockholm System, Inc. (Water)
Lake Tamarack Water Company
Lawrenceville Water Company
(5) Middlesex Water Company
Midtown Water Company
Montague Water Company
Mount Olive Villages Water Company, Inc.
(6) New Jersey-American Water Company, Inc. (Water Division)
New Jersey Vasa Home (Water)
Parkway Water Company
Pennsgrove Water Supply Company
Pinelands Water Company
Roxbury Water Company
Roxiticus Water Company, Inc.
S.B. Water Company, Inc.
(7) Seabrook Water Corporation
Seaview Water Company
Shore Water Company
Shorelands Water Company, Inc.
Simmons Water Company, Inc.
South Jersey Water Supply Company
Tranquility Springs Water Company, Inc.
United Water Arlington Hills, Inc. (Water)
United Water Hampton, Inc. (Water)
United Water Lambertville (Water)
United Water Matchaponix, Inc. (Water)
United Water New Jersey, Inc. (Water)
United Water Toms River (Water)
United Water Vernon Hills, Inc. (Water)
Vernon Water Company, Inc.
Wallkill Water Company

Total Number of Companies

1. Consumers New Jersey Water Company changed its name to Aqua New Jersey, Inc. on February 3, 2004.

2. NUI Utilities, Inc. d/b/a Elizabethtown Gas Company changed its name to Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company on March 11, 2005.

3. Berkeley Water Company sold its water system assets to Aqua New Jersey, Inc. on November 22, 2005.

4. Lake Valley Water Company sold its water system assets to Pemberton Township, NJ on December 22, 2005.

5. Bayview Water Company merged with and into Middlesex Water Company on January 1, 2006.

6. The Mount Holly Water Company merged with and into Elizabethtown Water Company on December 31, 2006. Elizabethtown Water Company merged with and into New Jersey-American Water Co., Inc. on December 31, 2006.

7. Seabrook Water Corporation sold its water system assets to Upper Deerfield Township, NJ on March 12, 2007.

Updated: Thursday, 07/19/2007

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Decide with Confidence

Business Information Report

To save report(s) to your PC, click here for instructions.

Print this Report

ATTN: **jbenthin@intell-group.com**

Report Printed: DEC 03 2007
In Date

BUSINESS SUMMARY

PIVOTAL UTILITY HOLDINGS, INC.
(SUBSIDIARY OF AGL RESOURCES INC., ATLANTA, GA)
1085 Morris Ave #1
Union, NJ 07083

Now Included with this Report NEW!

D&B's Credit Limit Recommendation
D&B's industry and risk-based limit guidance
Learn More View Now

Payment Trends Profile
Payment trends and industry benchmarks
Learn More View Now

This is a **headquarters (subsidiary)** location.
Branch(es) or division(s) exist.

Mailing address:	PO Box 760 Bedminster, NJ 07921
Web site:	www.aglresources.com
Telephone:	908 781-0500
Fax:	908 781-0718
Chief executive:	JOHN KEAN JR, PRES-CEO
Year started:	1969
Management control:	2006
Employs:	940 (155 here)
History:	CLEAR
Financing:	SECURED
SIC:	4924
Line of business:	Natural gas distribution

D-U-N-S Number:	05-671-1344
D&B Rating:	--
D&B PAYDEX®:	

12-Month D&B PAYDEX: 70
When weighted by dollar amount, payments to suppliers average 15 days beyond terms.

Based on trade collected over last 12 months.

NEW! Enhanced payment trends and industry benchmarks are available on this business

SUMMARY ANALYSIS

D&B Rating:--

The blank rating symbol should not be interpreted as indicating that credit should be denied. It simply means that the information available to D&B does not permit us to classify the company within our rating key and that further enquiry should be made before reaching a decision. Some reasons for using a "-" symbol include: deficit net worth, bankruptcy proceedings, insufficient payment information, or incomplete history information. For more information, see the D&B Rating Key.

BAC000013

Below is an overview of the company's rating history since 02/25/06:

D&B Rating	Date Applied
--	02/25/06

The Summary Analysis section reflects information in D&B's file as of December 3, 2007.

NEW! How does PIVOTAL UTILITY HOLDINGS, INC.'s payment record compare to its industry?
A Payment Trends Profile will show you - View Now

CUSTOMER SERVICE

If you have questions about this report, please call our Customer Resource Center at 1.800.234.3867 from anywhere within the U.S. If you are outside the U.S. contact your local D&B office.

*** Additional Decision Support Available ***

Additional D&B products, monitoring services and specialized investigations are available to help you evaluate this company or its industry. Call Dun & Bradstreet's Customer Resource Center at 1.800.234.3867 from anywhere within the U.S. or visit our website at www.dnb.com.

HISTORY

The following information was reported **08/09/2007**:

Officer(s): JOHN KEAN JR PRES - CEO
MARK ABRAMOVIC, SR VP-CFO-COO

DIRECTOR(S): The officers identified by (+)

Business started 1969. Present control succeeded 2006. 100% of capital stock is owned by NUI Corproation.

RECENT EVENTS:

On October 17, 2002, an inside source, stated that Piedmont Natural Gas (Charlotte, NC) has closed on its purchase of North Carolina Gas Service (Reidsville, NC), the natural gas distribution division of NUI Corporation (Bedminster, NJ) for approximately $26 million, subject to post-closing adjustment. The acquired location will now operate as a branch of Piedmont Natural Gas. The employees were retained. Further details are unavailable.

JOHN KEAN JR born 1950. 1995- present active here.

MARK ABRAMOVIC born 1952. 1997- present active here.

CORPORATE FAMILY

Click below to buy a Business Information Report on that family member.
For an expanded, more current corporate family view, use D&B's Global Family Linkage product.

Buy Selected Report(s)

Parent:

Agl Resources Inc.	Atlanta, GA	DUNS # 93-395-6211

Branches (US):

Pivotal Utility Holdings, Inc	Elizabeth, NJ	DUNS # 62-585-8055
Pivotal Utility Holdings, Inc	Rahway, NJ	DUNS # 02-357-9977
Pivotal Utility Holdings, Inc	Stewartsville, NJ	DUNS # 09-494-5511

Pivotal Utility Holdings, Inc	Reidsville, NC	DUNS # 04-147-9023
Pivotal Utility Holdings, Inc	Chesapeake, VA	DUNS # 04-532-7371
Pivotal Utility Holdings, Inc.	Hialeah, FL	DUNS # 18-765-8539
Pivotal Utility Holdings, Inc.	Port Saint Lucie, FL	DUNS # 95-786-7526
Pivotal Utility Holdings, Inc.	Rockledge, FL	DUNS # 04-304-4734
Pivotal Utility Holdings, Inc.	Elkton, MD	DUNS # 02-258-4213
Pivotal Utility Holdings, Inc.	Union, NJ	DUNS # 86-142-4067

Affiliates (US):*(Affiliated companies share the same parent company as this business.)*

A G L Capital Corporation	Atlanta, GA	DUNS # 11-980-5179
A G L Networks, LLC	Atlanta, GA	DUNS # 11-984-4624
Agl Capital Corporation	Las Vegas, NV	DUNS # 06-653-4285
Agl Resources Service Company	Atlanta, GA	DUNS # 00-505-9402
Atlanta Gas Light Company	Atlanta, GA	DUNS # 00-692-4708
Compass Energy Services Inc	Richmond, VA	DUNS # 09-539-6433
Energy Wise Services Inc	Atlanta, GA	DUNS # 00-753-5438
Georgia Energy Company	Atlanta, GA	DUNS # 82-479-9795
N U I Capital Corp	Bedminster, NJ	DUNS # 06-567-3865
Nui Saltville Storage, Inc	Saltville, VA	DUNS # 13-505-6427
Sequent Energy Management L.p	Houston, TX	DUNS # 61-207-5846
South Star Energy Services L. L. C.	Atlanta, GA	DUNS # 02-670-2220
Virginia Gas Pipeline Company	Abingdon, VA	DUNS # 96-020-1218
Virginia Gas Storage Company	Abingdon, VA	DUNS # 87-263-6626
Virginia Natural Gas, Inc	Norfolk, VA	DUNS # 15-049-1314

Buy Selected Report(s)

BUSINESS REGISTRATION

CORPORATE AND BUSINESS REGISTRATIONS PROVIDED BY MANAGEMENT OR OTHER SOURCE

The Corporate Details provided below may have been submitted by the management of the subject business and may not have been verified with the government agency which records such data.

Registered Name: NUI CORPORATION

Business type: CORPORATION
Corporation type: PROFIT
Date incorporated: FEB 03 2000
State of incorporation: NEW JERSEY
Filing date: FEB 03 2000
Registration ID: 0100806102
Status: ACTIVE

Where filed: DEPT OF STATE, TRENTON, NJ

OPERATIONS

08/09/2007

Description: Subsidiary of Agl Resources Inc., Atlanta, GA.

Provides natural gas distribution (100%).

Terms are net 30 days. Sells to commercial concerns. Territory : Local.

Nonseasonal.

Employees: 940 which includes officer(s). 155 employed here.

Facilities: Shares 13,000 sq. ft. in a three story brick building.

Location: Suburban business section on well traveled highway.

Branches: This business has multiple branches, detailed branch/division information is available in Dun & Bradstreet's linkage or family tree products.

SIC & NAICS

SIC:
Based on information in our file, D&B has assigned this company an extended 8-digit SIC. D&B's use of 8-digit SICs enables us to be more specific to a company's operations than if we use the standard 4-digit code.

The 4-digit SIC numbers link to the description on the Occupational Safety & Health Administration (OSHA) Web site. Links open in a new browser window.

49240000 Natural gas distribution

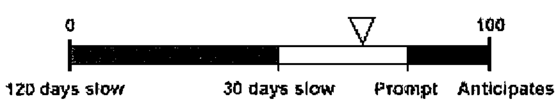
NAICS:
221210 Natural Gas Distribution

D&B PAYDEX

NEW! Enhanced payment trends and industry benchmarks are available on this business

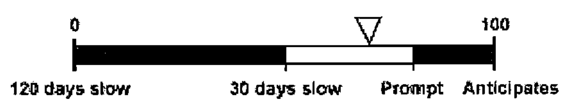
The D&B PAYDEX is a unique, dollar weighted indicator of payment performance based on up to 66 payment experiences as reported to D&B by trade references.

3-Month D&B PAYDEX: 68
When weighted by dollar amount, payments to suppliers average 17 days beyond terms.



Based on trade collected over last 3 months.

12-Month D&B PAYDEX: 70
When weighted by dollar amount, payments to suppliers average 15 days beyond terms.



Based on trade collected over last 12 months.

When dollar amounts are not considered, then approximately 86% of the company's payments are within terms.

PAYMENT SUMMARY

The Payment Summary section reflects payment information in D&B's file as of the date of this report.

Below is an overview of the company's dollar-weighted payments, segmented by its suppliers' primary industries:

	Total Rcv'd (#)	Total Dollar Amts ($)	Largest High Credit ($)	Within Terms (%)	Days Slow <31 (%)	31-60	61-90	90>
Top industries:								
Nonclassified	7	88,600	60,000	63	37	-	-	-

Misc equipment rental	6	2,750	500	100	-	-	-	-
Electric services	5	28,350	20,000	29	71	-	-	-
Whol office equipment	4	6,500	2,500	56	6	-	-	38
Public finance	2	2,550	2,500	100	-	-	-	-
Telephone communictns	2	2,600	2,500	100	-	-	-	-
Newspaper-print/publ	1	35,000	35,000	50	50	-	-	-
Detective/guard svcs	1	25,000	25,000	100	-	-	-	-
Mfg relays/controls	1	5,000	5,000	100	-	-	-	-
Regulate trnsprtation	1	2,500	2,500	100	-	-	-	-
OTHER INDUSTRIES	31	7,950	1,000	88	1	6	5	-
Other payment categories:								
Cash experiences	3	0	0					
Payment record unknown	1	50	50					
Unfavorable comments	1	50	50					
Placed for collections:								
With D&B	0	0						
Other	0	N/A						
Total in D&B's file	66	206,900	60,000					

The highest **Now Owes** on file is $10,000

The highest **Past Due** on file is $1,000

D&B receives over 600 million payment experiences each year. We enter these new andupdated experiences into D&B Reports as this information isreceived.

NEW! How does PIVOTAL UTILITY HOLDINGS, INC.'s payment record compare to its industry?
A Payment Trends Profile will show you - View Now

PAYMENT DETAILS

Detailed Payment History

Date Reported (mm/yy)	Paying Record	High Credit ($)	Now Owes ($)	Past Due ($)	Selling Terms	Last Sale Within (months)
10/07	Ppt		500	0		1 mo
	Ppt		500	0		1 mo
	Ppt		500	0		1 mo
	Ppt		250	0		1 mo
	Ppt		500	0		1 mo
	Ppt	25,000	10,000	0		1 mo
	Ppt	10,000	7,500	0		1 mo
	Ppt	10,000	5,000	0		1 mo
	Ppt	5,000	2,500			1 mo
	Ppt	5,000	0	0		6-12 mos
	Ppt	2,500	2,500			1 mo
	Ppt	750	500			1 mo
	Ppt	750	0	0	Lease Agreemnt	6-12 mos
	Ppt	500	0	0		2-3 mos
	Ppt	500	0	0		6-12 mos
	Ppt	500	500	0	N30	1 mo
	Ppt	100	100	0		1 mo

	Ppt-Slow	100	100			1 mo
	Ppt-Slow 15	1,000	500	500		1 mo
	Ppt-Slow 30	60,000	0	0		2-3 mos
	Ppt-Slow 30	35,000	0	0		2-3 mos
	Ppt-Slow 30	750	750	100	Lease Agreemnt	1 mo
	Ppt-Slow 30	100	100	0		1 mo
	Ppt-Slow 120	2,500	1,000	1,000		1 mo
	Ppt-Slow 120+	2,500	0	0	N30	4-5 mos
	Slow 120	20,000	2,500			1 mo
	Slow 30	2,500	1,000	0		1 mo
	Slow 60	500	0	0		6-12 mos
	(029)	50	0	0		4-5 mos
	(030)	50	50	50		
	Bad debt.					
	(031)	0	0	0	Cash account	1 mo
	(032)	0	0	0	Cash account	1 mo
09/07	Disc	250	250	0		1 mo
	Ppt	2,500				1 mo
	Ppt	1,000	0	0		1 mo
	Ppt	100	100	0	N10	1 mo
	Ppt	0	0	0	N30	1 mo
	Ppt-Slow 90	250	250	250		1 mo
08/07	Ppt	50	0	0		1 mo
07/07	Ppt	500	500	0		1 mo
	Ppt	250	250	0		1 mo
	Ppt	50	50	0		1 mo
	(043)				Sales COD	1 mo
06/07	Ppt	1,000	1,000			1 mo
	Ppt	250	250			1 mo
	Ppt	100	100			1 mo
	Ppt	100	0	0		6-12 mos
	Ppt	50	50			1 mo
	Ppt	50	50			1 mo
05/07	Ppt	2,500	2,500	0		1 mo
	Ppt	100	0	0		6-12 mos
	Ppt	0	0	0		1 mo
	Ppt	0	0	0		1 mo
	Ppt	0	0	0		1 mo
	Ppt	0	0	0		1 mo
	Ppt	0	0	0		1 mo
	Slow 10	0	0	0		6-12 mos
04/07	(058)	2,500				1 mo
	Satisfactory.					
03/07	Ppt	500	100	0		1 mo
12/06	Slow 90	250	250	250		
11/06	Ppt	5,000	0	0		6-12 mos
08/06	Slow 30	100	0	0		4-5 mos
06/06	Ppt	50				1 mo
	(064)	0	0	0		1 mo
	Satisfactory.					
05/06	Ppt	1,000				1 mo
	Ppt	500	0	0		6-12 mos

Payment experiences reflect how bills are met in relation to the terms granted. In some instances payment beyond terms can be the result of disputes over merchandise, skipped invoices etc.

Each experience shown is from a separate supplier. Updated trade experiences replace those previously reported.

NEW! **How does PIVOTAL UTILITY HOLDINGS, INC.'s payment record compare to its industry?**
A Payment Trends Profile will show you - View Now

FINANCE

06/05/2007

On June 5, 2007, attempts to contact the management of this business have been unsuccessful. Outside sources confirmed operation and location.

PUBLIC FILINGS

The following Public Filing data is for information purposes only and is not the official record. Certified copies can only be obtained from the official source.

SUITS

Status:	**Pending**
DOCKET NO.:	L 002357 06
Plaintiff:	THOMAS DAVEY
Defendant:	ELIZABETHTOWN GAS COMPANY, UNION, NJ
Cause:	TORT - OTHER
Where filed:	SUPERIOR COURT OF UNION COUNTY, ELIZABETH, NJ
Date status attained:	06/28/2006
Date filed:	06/28/2006
Latest Info Received:	10/23/2006

Status:	**Pending**
DOCKET NO.:	L 002610 06
Plaintiff:	MERCEDES RAYME
Defendant:	ELIZABETHTOWN GAS COMPANY, UNION, NJ AND OTHERS
Cause:	TORT - OTHER
Where filed:	ESSEX COUNTY SUPERIOR COURT, NEWARK, NJ
Date status attained:	03/28/2006
Date filed:	03/28/2006
Latest Info Received:	09/26/2006

Status:	**Pending**
DOCKET NO.:	L 002741 06
Plaintiff:	SAMANTHA THOMAS
Defendant:	ELIZABETHTOWN GAS CO, UNION, NJ AND OTHERS
Cause:	Product liability
Where filed:	ESSEX COUNTY SUPERIOR COURT, NEWARK, NJ
Date status attained:	03/28/2006
Date filed:	03/28/2006
Latest Info Received:	09/26/2006

Status:	**Pending**
DOCKET NO.:	L 000043 06
Plaintiff:	NELSON DASILVA
Defendant:	ELIZABETHTOWN GAS CO, UNION, NJ AND OTHERS
Cause:	Product liability
Where filed:	SUPERIOR COURT OF UNION COUNTY, ELIZABETH, NJ
Date status attained:	01/05/2006

Date filed:	01/05/2006
Latest Info Received:	05/22/2006

Suit amount:	**$7,131**
Status:	**Dismissed**
DOCKET NO.:	DC-000323-2006
Plaintiff:	LAWRENCE MORSE
Defendant:	ELIZABETHTOWN GAS, UNION, NJ
Cause:	CONTRC-REG
Where filed:	SPECIAL CIVIL/SMALL CLAIMS COURT OF UNION COUNTY, ELIZABETH, NJ
Date status attained:	03/02/2006
Date filed:	12/30/2005
Latest Info Received:	04/24/2006

Status:	**Pending**
DOCKET NO.:	L 007929 05
Plaintiff:	GARY ALLEN LLC
Defendant:	ELIZABETHTOWN GAS COMPANY, UNION, NJ AND OTHERS
Where filed:	MIDDLESEX COUNTY SUPERIOR COURT, NEW BRUNSWICK, NJ
Date status attained:	11/03/2005
Date filed:	11/03/2005
Latest Info Received:	07/24/2006

Status:	**Pending**
DOCKET NO.:	L 003530 05
Plaintiff:	MASSACHUSETTS BAY INSURANCE CO
Defendant:	ELIZABETHTOWN GAS COMPANY, UNION, NJ AND OTHERS
Cause:	TORT - OTHER
Where filed:	SUPERIOR COURT OF UNION COUNTY, ELIZABETH, NJ
Date status attained:	10/03/2005
Date filed:	10/03/2005
Latest Info Received:	03/06/2006

Status:	**Pending**
DOCKET NO.:	L 003328 05
Plaintiff:	MARYLAND CASUALTY COMPANY
Defendant:	ELIZABETHTOWN GAS COMPANY, UNION, NJ
Cause:	TORT - OTHER
Where filed:	SUPERIOR COURT OF UNION COUNTY, ELIZABETH, NJ
Date status attained:	09/13/2005
Date filed:	09/13/2005
Latest Info Received:	03/06/2006

Status:	**Settled**
DOCKET NO.:	L 001549 05
Plaintiff:	ELISA TAVAREZ
Defendant:	ELIZABETHTOWN GAS COMPANY, UNION, NJ AND OTHERS
Cause:	CONTRACT
Where filed:	MIDDLESEX COUNTY SUPERIOR COURT, NEW BRUNSWICK, NJ
Date status attained:	08/25/2006
Date filed:	02/25/2005
Latest Info Received:	11/27/2006

Status:	**Pending**
DOCKET NO.:	L 001421 05
Plaintiff:	DAVID RAMOS
Defendant:	ELIZABETHTOWN GAS COMPANY, UNION, NJ AND OTHERS
Cause:	AUTO NEGLIGENCE
Where filed:	MIDDLESEX COUNTY SUPERIOR COURT, NEW BRUNSWICK, NJ
Date status attained:	02/22/2005
Date filed:	02/22/2005
Latest Info Received:	09/26/2005

If it is indicated that there are defendants other than the report subject, the lawsuit may be an action to clear title to property and does not necessarily imply a claim for money against the subject.

LIENS

A lienholder can file the same lien in more than one filing location. The appearance of multiple liens filed by the same lienholder against a debtor may be indicative of such an occurrence.

Amount:	**$11,675**
Status:	**Open**
BOOK/PAGE:	2251/0867
Type:	State Tax
Filed by:	FLORIDA, STATE OF
Against:	NUI CORPORATION, UNION, NJ
Where filed:	LEON COUNTY RECORDERS OFFICE, TALLAHASSEE, FL
Date status attained:	05/13/1999
Date filed:	05/13/1999
Latest Info Received:	11/24/2004

UCC FILINGS

Collateral:	All Inventory and proceeds - All Account(s) and proceeds - All General intangibles (s) and proceeds - All Equipment and proceeds - All Chattel paper and proceeds
Type:	Original
Sec. party:	ASSOCIATED WHOLESALERS, INC., ROBESONIA, PA
Debtor:	ELKTON GAS SERVICE, INC., ELKTON, MD
Filing number:	00000181141603
Filed with:	UCC DIVISION, BALTIMORE, MD
Date filed:	01/16/2003
Latest Info Received:	02/19/2003

Collateral:	All Account(s) and proceeds - All General intangibles(s) and proceeds - All Contract rights and proceeds - Leased Computer equipment and proceeds - Leased Equipment and proceeds
Type:	Original
Sec. party:	LONGSHORE SYSTEMS, INC., WESTPORT, CT
Assignee:	SUMMIT BANK, CRANFORD, NJ
Debtor:	NUI CORPORATION, UNION, NJ
Filing number:	2004751
Filed with:	SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ
Date filed:	10/23/2000
Latest Info Received:	11/16/2000

Collateral:	Account(s) and proceeds
Type:	Original
Sec. party:	CREDIT SUISSE FIRST BOSTON, CAYMAN ISLANDS BRANCH, AS COLLATERAL AGENT, NEW YORK, NY
Debtor:	NUI UTILITIES, INC., UNION, NJ
Filing number:	22593221
Filed with:	SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ
Date filed:	09/30/2004
Latest Info Received:	10/18/2004

Collateral:	Account(s) and proceeds - Leased Assets and proceeds - General intangibles(s) and proceeds - Chattel paper and proceeds - Leased Equipment and proceeds
Type:	Original
Sec. party:	FLEET CAPITAL CORPORATION, PROVIDENCE, RI
Debtor:	NUI UTILITIES, INC.
Filing number:	21151705
Filed with:	SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ
Date filed:	07/26/2002
Latest Info Received:	09/09/2002

Type:	Amendment

Sec. party:	BANC OF AMERICA LEASING & CAPITAL, LLC
Debtor:	PIVOTAL UTILITY HOLDINGS, INC.
Filing number:	21151705
Filed with:	SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ
Date filed:	12/15/2005
Latest Info Received:	01/11/2006
Original UCC filed date:	07/26/2002
Original filing no.:	21151705

Collateral:	Leased Assets - Leased Business machinery/equipment
Type:	Original
Sec. party:	CANON FINANCIAL SERVICES, INC., MT. LAUREL, NJ
Debtor:	NUI CORPORATION, UNION, NJ and OTHERS
Filing number:	21229343
Filed with:	SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ
Date filed:	09/18/2002
Latest Info Received:	10/23/2002

Collateral:	Leased Assets - Leased Equipment - Leased Business machinery/equipment
Type:	Original
Sec. party:	CANON FINANCIAL SERVICES, INC., MT. LAUREL, NJ
Debtor:	NUI CORPORATION, UNION, NJ and OTHERS
Filing number:	21109157
Filed with:	SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ
Date filed:	07/01/2002
Latest Info Received:	07/29/2002

Collateral:	Leased Assets - Leased Equipment
Type:	Original
Sec. party:	CANON FINANCIAL SERVICES, INC., MOUNT LAUREL, NJ
Debtor:	NUI TELECOM INC, UNION, NJ and OTHERS
Filing number:	2080880
Filed with:	SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ
Date filed:	12/31/2001
Latest Info Received:	02/19/2002

Collateral:	Business machinery/equipment - Leased Equipment
Type:	Original
Sec. party:	U S BANCORP, MARSHALL, MN
Debtor:	NUI CORPORATION, ROCKLEDGE, FL and OTHERS
Filing number:	200100184643
Filed with:	SECRETARY OF STATE/UCC DIVISION, TALLAHASSEE, FL
Date filed:	08/24/2001
Latest Info Received:	08/29/2001

Collateral:	Leased Business machinery/equipment and proceeds - Leased Computer equipment and proceeds
Type:	Original
Sec. party:	DANKA OFFICE IMAGING COMPANY, CEDAR RAPIDS, IA
Debtor:	NUI CORPORATION, UNION, NJ and OTHERS
Filing number:	1844299
Filed with:	SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ
Date filed:	06/19/1998
Latest Info Received:	07/14/1998

Collateral:	Leased Computer equipment - Leased Communications equipment - Leased Fixtures - Leased Equipment - Leased Vehicles
Type:	Original
Sec. party:	BLC CORPORATION, HARRISON, NY
Debtor:	NUI CORPORATION, UNION, NJ
Filing number:	2068470
Filed with:	SECRETARY OF STATE/UCC DIVISION, TRENTON, NJ
Date filed:	10/09/2001

Latest Info Received: 11/05/2001

There are additional UCC's in D&B's file on this company available by contacting 1-800-234-3867.

There are additional suits, liens, or judgments in D&B's file on this company available by contacting 1-800-234-3867.

The public record items contained in this report may have been paid, terminated, vacated or released prior to the date this report was printed.

GOVERNMENT ACTIVITY

Activity summary

Borrower (Dir/Guar):	NO
Administrative debt:	NO
Contractor:	YES
Grantee:	NO
Party excluded from federal program(s):	NO

Possible candidate for socio-economic program consideration

Labor surplus area:	YES (2007)
Small Business:	N/A
8(A) firm:	N/A

The details provided in the Government Activity section are as reported to Dun & Bradstreet by the federal government and other sources.

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SECURITIES AND EXCHANGE COMMISSION

(Release No. 35-28038; 70-10304)

AGL Resources Inc.

Order Authorizing the Acquisition of Nonutility Businesses and Participation in the System Money Pool

September 28, 2005

AGL Resources Inc. ("AGL"), Atlanta, Georgia, a registered holding company has filed an application-declaration ("Application") with the Securities and Exchange Commission ("Commission") under sections 6(a), 7, 9(a), 10, 11(b) and 12(b) of the Public Utility Holding Company Act of 1935, as amended ("Act") and rule 54 under the Act. On July 27, 2005, the Commission issued notice of the Application (Holding Co. Act Release No. 28004).

AGL requests authority to organize and finance one or more direct or indirect subsidiaries to engage in certain gas- and energy-related nonutility businesses in Canada, Mexico and/or the United States.

I. Background

AGL distributes natural gas to more than 2.2 million end-use customers through public-utility company subsidiaries organized in Georgia (Atlanta Gas Light Company), Tennessee (Chattanooga Gas Company), Virginia (Virginia Natural Gas Inc. and Virginia Gas Distribution Company) and New Jersey (Pivotal Utility Holdings, Inc.). Pivotal Utility Holdings owns and operates utility facilities in New Jersey, Florida and Maryland through the following divisions: Elizabethtown Gas, Florida City Gas, and Elkton Gas.

AGL is also involved in various energy- and gas-related nonutility businesses, including: retail natural gas marketing to end-use customers in Georgia; natural gas asset management and related logistics activities for its own utilities as well as for other non-affiliated companies;

operation of high deliverability underground natural gas storage; and construction and operation of telecommunications conduit and fiber infrastructure within select metropolitan areas. The common stock of AGL is listed on the New York Stock Exchange.

Through various subsidiaries, Sequent, LLC ("Sequent"), an indirect, wholly-owned subsidiary company of AGL, is engaged in the optimization of natural gas assets, gas transportation and storage, producer and peaking services and the wholesale marketing of natural gas. Sequent's asset optimization business focuses on capturing value from idle or underutilized natural gas assets, which are typically amassed by companies via investments in, or contractual rights to, natural gas transportation and storage facilities. Margins are typically created in this business by participating in transactions that balance the needs of varying markets and time horizons. Sequent provides its customers with natural gas from the major producing regions and market hubs primarily in the Eastern and Mid-Continental United States. Sequent also purchases transportation and storage capacity to meet its delivery requirements and customer obligations in the marketplace. Sequent's customers benefit from its logistics expertise and ability to deliver natural gas at prices that are advantageous relative to the other alternatives available to its end-use customers.

II. Requests For Authority

AGL requests authority to acquire interests in energy- and gas-related nonutility businesses operating in Canada, Mexico and/or the U.S ("Foreign Nonutility Businesses").[1] Typically, these investments will be made through one or more direct or indirect subsidiaries of Sequent and funded by acquisitions of equity and debt securities of Foreign Nonutility

[1] Rule 58 does not permit the acquisition of these businesses because "substantially all" of their revenues will not be derived from activities within the United States.

Businesses, borrowings from AGL's nonutility money pool by Foreign Nonutility Businesses, and guarantees.[2] AGL will limit its direct and indirect investments in Foreign Nonutility Businesses to an aggregate amount not to exceed $300 million ("Investment Limit") in the form of equity, debt and guarantees, including nonutility money pool borrowings, through February 8, 2006 ("Authorization Period").[3]

The specific nonutility businesses in which AGL seeks authorization to invest include: (1) energy management services and other energy conservation related businesses;[4] (2) the maintenance and monitoring of utility equipment; (3) the provision of utility related or derived

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[2] The proposed investments would be subject to the limits set forth in Holding Co. Act Release No. 27828, (April 1, 2004). In addition, AGL's public-utility company subsidiaries will not directly or indirectly acquire any Foreign Nonutility Businesses, and they will not provide funding for, extend credit to, or guarantee the obligations of Foreign Nonutility Businesses.

[3] AGL's investments in "gas-related companies" and "energy-related companies" within the meaning of rule 58 are subject to the investment limits under that rule, not to the Investment Limit.

[4] Energy management services include: the marketing, sale, installation, operation and maintenance of various products and services related to energy management and demand-side management, including energy and efficiency audits; meter data management, facility design and process control and enhancements; construction, installation, testing, sales and maintenance of (and training client personnel to operate) energy conservation equipment; design implementation, monitoring and evaluation of energy conservation programs; development and review of architectural, structural and engineering drawings for energy efficiency, design and specification of energy consuming equipment and general advice on programs; the design, construction, installation, testing, sales, operation and maintenance of new and retrofit heating, ventilating, and air conditioning, gas, electrical and power systems, alarm, security, access control and warning systems, motors, pumps, lighting, water, water-purification and plumbing systems, building automation and temperature controls, installation and maintenance of refrigeration systems, building infrastructure wiring supporting voice, video, data and controls networks, environmental monitoring and control, ventilation system calibration and maintenance, piping and fire protection systems, and design, sale, engineering, installation, operation and maintenance of emergency or distributed power generation systems, and related structures, in connection with energy-related needs; and the provision of services and products designed to prevent, control, or mitigate adverse effects of power disturbances on a customer's electrical systems.

software and services; (4) engineering, consulting and technical services, operations and maintenance services; (5) brokering and marketing of natural gas, electricity and other energy commodities and providing incidental related services, such as fuel management, storage and procurement; and (6) oil and gas exploration, development, production, gathering, transportation, storage, processing and marketing activities, and related or incidental activities. AGL is not seeking authority to acquire any assets that would cause any subsidiary to be or become an "electric-utility company" or "gas-utility company," as those terms are defined in sections 2(a)(3) and 2(a)(4) of the Act, respectively. AGL will report its investments in its Canadian and Mexican gas- and energy-related companies in a supplement to its regular quarterly reports filed on Form U-9C-3.

In addition, AGL requests authority for all Foreign Nonutility Businesses to participate as borrowers and lenders in the nonutility money pool authorized by Commission order dated April 1, 2004 (Holding Co. Act Release No. 27828). Participation in the nonutility money pool will include unsecured short-term borrowing, contributing surplus funds, and lending and extending credit to other nonutility money pool participants.

The proposed transaction is subject to rule 54, which provides that, in determining whether to approve certain transactions other than those involving exempt wholesale generators ("EWGs") or foreign utility companies ("FUCOs"), as defined in the Act, the Commission will not consider the effect of the capitalization or earnings of any subsidiary which is an EWG or FUCO if the requirements of rule 53(a), (b) and (c) under the Act are satisfied. AGL states that neither it nor any of its subsidiaries presently has an interest in any EWG or FUCO. Therefore, the requirements of rule 53 are satisfied.

III. Conclusion

AGL estimates that the fees, commission and expenses incurred in connection with the proposed transaction will be approximately $12,000. The company states that no state or federal commission, other than this Commission, has jurisdiction over the proposed transactions.

Due notice of the filing of the Application has been given in the manner prescribed, and no hearing has been requested of or ordered by the Commission. Upon the basis of the facts in the record, it is found that the applicable standards of the Act and rules are satisfied, and that no adverse findings are necessary.

IT IS ORDERED, that the Application, as amended, is granted and permitted to become effective immediately, subject to the terms and conditions contained in rule 24 under the Act.

For the Commission by the Division of Investment Management, pursuant to delegated authority.

Jonathan G. Katz
Secretary

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Blen

State of New Jersey

Department of Environmental Protection

Christine Todd Whitman
Governor

Robert C. Shinn, Jr.
Commissioner

August 27, 1999

Honorable Robert Menendez
US House of Representatives
Canon House Office Building, Room 405
Washington DC 20515-3013

Dear Congressman Menendez:

As you know, protecting the quality of our water is utmost in the minds of New Jersey's citizens. Within the State of New Jersey, 24 municipalities operate combined sewer systems, that is, sewer systems which convey both sanitary waste and stormwater and which discharge directly to surface water through combined sewer overflow ("CSO") points during wet weather events. For your information, I have attached a list of these municipalities and the number of their permitted CSO points. I know that you are aware of the significant amount of solids and floatables that enter our waterways from these types of overflows. Solids/Floatable materials in CSO discharges are aesthetically objectionable, environmentally deleterious, a potential health risk when encountered on the shoreline, injurious to biota, and a possible navigational hazard.

The Department, working closely with USEPA, developed and issued a general permit for Combined Sewer Systems. The permit, consistent with the National CSO Control Policy, requires communities with combined sewer systems, to mitigate the impacts of their combined sewer overflows through proper operation and maintenance programs, maximum conveyance of wastewater flows to a treatment facility, and effective solids/floatables control measures. Compliance with the permit is not conditioned in any way on the receipt of financial assistance, and enforcement actions are being instituted against delinquent municipalities. Nevertheless, the Department recognizes the associated costs to comply with the requirements of the National CSO Control Policy are significant.

One of the communities with a combined sewer system, the City of Elizabeth, has asked the Department to endorse its request for financial assistance from the Federal Government. The City of Elizabeth is seeking federal assistance to rehabilitate its combined sewer system and comply with all of the requirements of the National CSO

Control Policy including the control of solids and floatables. To that end, I am writing to request that you give all of New Jersey's communities with combined sewer systems, including the City of Elizabeth, your attention as you craft this year's federal budget.

Your action on this matter would be greatly appreciated. Please contact me if you need any further information.

Sincerely,

Robert C. Shinn, Jr.
Commissioner

V:Jim/Elizabeth l

c: Mayor Bollwage, City of Elizabeth
Dennis Hart, Director, Division of Water Quality
James Hamilton, Administrator, Water Compliance and Enforcement

Facility Name	Permitted CSO Points
Bayonne	33
Bergen County UA	0
Boro of East Newark	1
Boro of Fort Lee	2
Camden County MUA	1
City of Camden	31
City of Elizabeth	33
City of Hackensack	2
City of New Brunswick	1
City of Newark	30
City of Paterson	31
City of Rahway	5
Trenton Utility Authority	1
Cliffside Park	0
Edgewater MUA	7
Gloucester City	7
Guttenberg	1
Jersey City MUA	27
Joint Mtg Essex & Union Co.	0
Middlesex County UA	0
North Bergen Twp. MUA	12
North Bergen MUA -Woodcliff	1
North Hudson SA-Hoboken	11
Passaic Valley SC	0
Rahway Valley SA	0
Ridgefield Park	6
Town of Harrison	7
Town of Kearny	10
North Hudson SA-WNY	2
City of Perth Amboy	18
TOTAL :	**280**

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NJ0108782-04LS

CERTIFIED MAIL NO.
P239 234 684

State of New Jersey

Christine Todd Whitman
Governor

Department of Environmental Protection

Robert C. Shinn, Jr.
Commissioner

FEB 28 2000

Honorable Mayor J. Christian Bollwage
Mayor, City of Elizabeth
50 Winfield Scott Plaza
Elizabeth, NJ 07201

SUBJECT: New Jersey Pollutant Discharge Elimination System
General Permit No. NJ0105023
Permit Re-issuance

Dear Mayor Bollwage:

Enclosed is the final reissued NJPDES General Permit NJ0105023 for Combined Sewer Systems with the Response to Comments Document as required by N.J.A.C. 7:14A-15.16. General Permit No. NJ0105023 was issued on February 28, 2000, has an Effective Date February 29, 2000 and will expire on February 28, 2005. The permit has been issued in accordance with the provisions of N.J.A.C. 7:14A.

The general permit has been re-issued with minor modifications as proposed in the draft permit re-issuance that do not impact the substantive provisions of the original permit. The most significant modification to the permit is the incorporation of paragraphs I.E. 3 & 4 that provide for the automatic renewal of existing authorizations as provided by N.J.A.C. 7:14A-6.13 (d) 9.

Within thirty (30) calendar days following your receipt of this permit, under N.J.A.C. 17:14A 17.2 you may submit a request for an adjudicatory hearing to reconsider or contest the conditions of this permit. Regulations regarding the format and requirements for requesting an adjudicatory hearing may by found in N.J.A.C. 7:14A-17.2 (a) through (f). The request should be made to:

Stanley V. Cach, Jr., PE, PP, Chief
Bureau of Engineering North
PO Box 425
Trenton, NJ 08625-0425

Additionally, the request for an adjudicatory hearing must contain a completed, signed and dated "Administrative Hearing Request Checklist and Tracking Form for Permits" (form attached). The original forms shall be submitted to the Office of Legal Affairs and two copies submitted to the Division of Water Quality at the addresses listed on the attached form.

If you have any questions concerning the revocation and re-issuance of the permit, please contact Stanley V. Cach, PE, PP, Chief, Bureau of Engineering North at (609) 292-6894 or Gautam R. Patel, Chief, Bureau of Engineering South at (609) 984-6840.

Sincerely,

Dennis Hart
Director

ENCLOSURES
General Permit for Combined Sewer Systems and attachments
Request For Authorization and instructions
Notice to Permittees of Final Permit Decision
Administrative Hearing Request Checklist and Tracking Form for Permits

CERTIFIED MAIL NO.
P239 234 478

State of New Jersey

Christine Todd Whitman
Governor

Department of Environmental Protection

Robert C. Shinn, Jr.
Commissioner

February 28, 2000

Mr. Blaise E. Lapolla
City of Elizabeth
50 Winfield Scott Plaza
Elizabeth, N.J. 07201-2462

SUBJECT: New Jersey Pollutant Discharge Elimination System
General Permit No. NJ0105023
Permit Re-issuance

GENTLEMEN:

Enclosed is the final reissued NJPDES General Permit NJ0105023 for Combined Sewer Systems with the Response to Comments Document as required by N.J.A.C. 7:14A-15.16. General Permit No. NJ0105023 was issued on February 28, 2000, has an Effective Date February 29, 2000 and will expire on February 28, 2005. The permit has been issued in accordance with the provisions of N.J.A.C. 7:14A.

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Sincerely,

Dennis Hart
Director

ENCLOSURES
General Permit for Combined Sewer Systems and attachments
Request For Authorization and instructions
Notice to Permittees of Final Permit Decision
Administrative Hearing Request Checklist and Tracking Form for Permits

CERTIFIED MAIL No.
P239 234 684

State of New Jersey

Christine Todd Whitman
Governor

Department of Environmental Protection
Bureau of Engineering North
Municipal Finance and Construction Element
PO BOX 425
Trenton, NJ 08625-0425

Robert C. Shinn, Jr.
Commissioner

February 28, 2000

Honorable Mayor J. Christian Bollwage
Mayor, City of Elizabeth
50 Winfield Scott Plaza
Elizabeth, NJ 07201

Dear Mayor Bollwage:

SUBJECT: New Jersey Pollutant Discharge Elimination System
NJPDES Permit No. NJ0105023
General Permit for Combined Sewer Systems
Notice of Automatic Renewal of Authorization
Individual Authorization No. NJ0108782

We are pleased to inform you that your Individual Authorization under the General Permit for Combined Sewer Systems NJPDES No. NJ0105023 was automatically renewed until February 28, 2005 pursuant to NJAC 7:14A-6.13. Enclosed with this letter you will find a copy of your renewed Individual Authorization. Please include a copy of the renewed Individual Authorization in the Combined Sewer Overflow Control Pollution Prevention Plan (CSOPPP).

The General Permit for Combined Sewer Systems NJPDES No. NJ0105023 is issued to control the discharge of pollutants from Combined Sewer Systems through Combined Sewer Overflow Points (CSO Points). The General Permit was re-issued on February 28, 2000, has an Effective Date of February 29, 2000 and will expire on February 28, 2005.

Existing authorizations were renewed automatically when the general permit was issued. The most recently submitted Request for Authorization (RFA) (A copy is enclosed.) was considered a timely and complete request for authorization under the reissued permit. The automatic renewal of an Individual Authorization was applicable for any permittee who had an Individual Authorization under the permit immediately prior to the effective date of the reissued permit.

Enclosed with this notice is a copy of the most recent RFA and the renewed Individual Authorization for your facilities. If any information contained in the Individual Authorization, specifically, any information contained in Table CSO-1, or that which is contained in the enclosed RFA of record, is no longer valid, accurate, and/or complete, the permittee is required to provide the correct information to the Department within 90-days after the effective date of the permit.

A copy of the general permit and a new RFA package is enclosed with this letter. Please complete the enclosed RFA and FORM A: SCHEDULE OF CSO POINTS and return the completed and signed RFA along with a FORM A to the Department at the address included on the RFA within 90-days after the effective date of the permit.

The Department appreciates your efforts toward accomplishing the goal of providing cleaner water for our State and looks forward to building upon our joint achievements.

Additional information concerning the Re-issued General Permit or the Renewal of the Individual Authorizations may be obtained between the hours of 8:00 AM and 4:00 PM, Monday thorough Friday by contacting Stanley V. Cach, PE, PP, Chief, Bureau of Engineering North at (609) 292-6894.

Sincerely,

Stanley V. Cach

Stanley V. Cach, Jr. PE, PP, Chief
Bureau of Engineering North
Municipal Finance & Construction

ENCLOSURES
Individual Authorization
RFA of record
New RFA package

CERTIFIED MAIL No.
P239 234 478

State of New Jersey

Christine Todd Whitman
Governor

Department of Environmental Protection
Bureau of Engineering North
Municipal Finance and Construction Element
PO BOX 425
Trenton, NJ 08625-0425

Robert C. Shinn, Jr.
Commissioner

February 28, 2000

Mr. Blaise E. Lapolla
City of Elizabeth
50 Winfield Scott Plaza
Elizabeth, N.J. 07201-2462

Dear Mr. Lapolla:

SUBJECT: New Jersey Pollutant Discharge Elimination System
NJPDES Permit No. NJ0105023
General Permit for Combined Sewer Systems
Notice of Automatic Renewal of Authorization
Individual Authorization No. NJ0108782

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Enclosed with this notice is a copy of the most recent RFA and the renewed Individual Authorization for your facilities. If any information contained in the Individual Authorization, specifically, any information contained in Table CSO-I, which is contained in the enclosed RFA of record, is no longer valid, accurate, and/or complete, the permittee is required to provide the correct information to the Department within 90-days after the effective date of the permit.

A copy of the general permit and a new RFA package is enclosed with this letter. Please complete the enclosed RFA and FORM A: SCHEDULE OF CSO POINTS and return the completed and signed RFA along with a FORM A to the Department at the address included on the RFA within 90-days after the effective date of the permit.

The Department appreciates your efforts toward accomplishing the goal of providing cleaner water for our State and looks forward to building upon our joint achievements.

Additional information concerning the Re-issued General Permit or the Renewal of the Individual Authorizations may be obtained between the hours of 8:00 AM and 4:00 PM, Monday thorough Friday by contacting Stanley Cach, Jr., PE, PP, Chief, Bureau of Engineering South at (609) 292-6894.

Sincerely,

Stanley V. Cach

Stanley Cach, Jr., PE, PP, Chief
Bureau of Engineering North
Municipal Finance & Construction

ENCLOSURES
Individual Authorization
RFA of record
New RFA package

NEW JERSEY POLLUTANT DISCHARGE ELIMINATION SYSTEM

The New Jersey Department of Environmental Protection hereby grants you a NJPDES permit for the facility/activity named in this document. This permit is the regulatory mechanism used by the department to ensure your discharge will not harm the environment. By complying with the terms and conditions specified, you are assuming an important role in protecting New Jersey's valuable water resources. Your acceptance of this permit is an agreement to conform with all of its provisions when constructing, installing, modifying, or operating any facility for the collection, treatment, or discharge of pollutants to waters of the state. If you have any questions about this document, please feel free to contact the department representative listed in the permit cover letter. Your cooperation in helping us protect and safeguard our state's environment is anticipated and appreciated.

PERMIT NUMBER NJ0108782

Permittee	Co-Permittee
ELIZABETH CITY OF 50 WINFIELD SCOTT PLAZA ELIZABETH NJ 07201	

Property Owner	Location of Activity
ELIZABETH CITY OF 50 WINFIELD SCOTT PLAZA ELIZABETH NJ 07201	ELIZABETH CITY OF 50 WINFIELD SCOTT PLAZA ELIZABETH NJ 07201

Current Authorization Covered By This Approval And Previous Authorization	Issuance Date	Effective Date	Expiration Date
CSO:COMBINED SEWER OVERFLOW (GP)	02/28/2000	02/29/2000	02/28/2005

By Authority of:

Stanley V. Cach

DEP AUTHORIZATION

Stanley V. Cach Jr., PE, PP
Chief, Bureau of Engineering North

(Terms, conditions and provisions attached hereto)

NJPDES/DSW PERMIT NUMBER NJ0108782
INDIVIDUAL AUTHORIZATION PAGE CONTINUED

This individual general permit authorization authorizes the City of Elizabeth to operate a combined sewer system for the collection and conveyance of wastewater and to discharge untreated wastewater in the form of combined sewer overflows from the combined sewer overflow points listed on the Table CSO-I, in accordance with terms and conditions of the General Permit for Combined Sewer Systems NJPDES Permit No. NJ0105023.

Table CSO-I

001	Alina St. No. 1	40°40'49"	74°11'30"	Peripheral Ditch
002	Dowd Ave. No. 2	40°40'19"	74°11'26"	Great Ditch
003	Westfield Ave. No. 3	40°40'04"	74°13'15"	Elizabeth River
005	Westfield Ave. No. 5	40°40'04"	74°13'11"	Elizabeth River
006	Crane St. No. 6	40°40'01"	74°13'09"	Elizabeth River
007	W. Grant, E. Bank	40°39'58"	74°13'09"	Elizabeth River
008	W. Grant St. W. Bank	40°39'58"	74°13'08"	Elizabeth River
009	Murray St. E. Bank	40°39'47"	74°13'09"	Elizabeth River
010	Murray St. W. Bank	40°39'47"	74°13'10"	Elizabeth River
011	Rahway Ave. W. Bank	40°39'41"	74°13'06"	Elizabeth River
012	Rahway Ave. E. Bank	40°39'41"	74°13'04"	Elizabeth River
013	S. of Rahway Ave.	40°39'39"	74°13'04"	Elizabeth River
014	Broad St. E. Bank	40°39'39"	74°12'57"	Elizabeth River
016	Broad St. W. Bank	40°39'38"	74°13'03"	Elizabeth River
017	Broad St. W. Bank	40°39'38"	74°12'56"	Elizabeth River
021	South Spring St. E. Bank	40°39'32"	74°12'53"	Elizabeth River
022	South St. E. Bank	40°39'28"	74°12'39"	Elizabeth River
025	Montgomery St., W. Bank	40°39'22"	74°12'40"	Elizabeth River
026	John St.,E. Bank	40°39'15"	74°12'33"	Elizabeth River
027	Summer St.,W. Bank	40°38'59"	74°12'37"	Elizabeth River
028	Summer St., W. Bank	40°38'59"	74°12'37"	Elizabeth River
029	S.Front St.,E. Bank	40°38'40"	74°11'26"	Elizabeth River
030	East Jersey St. & Front St.	40°38'47"	74°11'12"	Arthur Kill
031	Livingston St.	40°38'48"	74°11'09"	Arthur Kill
032	Magnolia Ave.	40°38'51"	74°10'53"	Arthur Kill
034	Puleo Plaza	40°39'07"	74°10'15"	Newark Bay
035	Third Ave., E. Bank	40°38'33"	74°11'43"	Elizabeth River
036	Irvington Ave. Dod Ct.	40°40'15"	74°13'12"	Elizabeth River
037	Bayway	40°38'06"	74°11'57"	Arthur Kill
038	Trenton Ave., E. Bank	40°38'46"	74°12'52"	Elizabeth River
039	Schiller St.	40°39'46"	74°12'52"	Great Ditch
040	Pulaski St., W. Bank	40°38'47"	74°12'32"	Elizabeth River
041	Morris Ave., W. Bank	40°40'10"	74°13'11"	Elizabeth River
042	Bridge St., E. Bank	40°39'32"	74°12'43"	Elizabeth River

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City of Elizabeth, New Jersey

COMBINED SEWER OVERFLOW POLLUTION ABATEMENT PROGRAM

Volume II

DRAFT

Clinton Bogert Associates

CONSULTING ENGINEERS

August, 1981

City of Elizabeth, New Jersey

COMBINED SEWER OVERFLOW POLLUTION ABATEMENT PROGRAM

Volume II

DRAFT

Clinton Bogert Associates
CONSULTING ENGINEERS

August, 1981

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VII. EVALUATION OF ALTERNATIVES

A. Introduction

To develop an effective abatement program, the characteristics of all real rainfall events as recorded at Newark Airport were analyzed for the period 1963 through 1974. The frequency distribution of precipitation total amounts and preceding dry hours by event have been previously presented. Sewer solids are deposited in streets and sewers during dry periods. These are removed in part, or in whole, by rainfall events, depending on their intensity, total amount and duration. Because of the frequent occurrence of rainfalls, the sewer system does not normally store great incremental amounts of the dry weather flow pollutant. Also, significant sewer solids deposits are restricted to a relatively small length of sewers in Elizabeth. However, pollutant deposits in streets are widely distributed, although usually in greater relative quantities in the commercial and industrial areas than in the residential areas.

B. Alternatives for CSO Pollution Abatement

Alternatives for the abatement of pollution from combined sewer overflows generally consist of the following: sewer separation, treatment including screening, settling and chlorination or the swirl separator, off-line storage (downstream near interceptor), in-line storage (upstream storage in sewers or tanks), flushing, non-structural techniques, and combinations of these alternatives.

1. Sewer Separation. Separation of the sewers in a combined basin can be costly and not effective. In Elizabeth an estimated 54 percent of the pollutants in CSO originate in surface washoff. A separate system would continue to discharge these pollutants, unless flow routing was introduced which would permit directing the initial

flush of rainfall runoff to treatment. Pollutants discharged from a combined system can be less than those from a separate system (both storm and sanitary) without incurring significant additional costs for the total system. If limited lengths are required to achieve separation, such works may be the cost-effective solution if the amount of pollutants generated in the area served is relatively small.

2. Combined Sewage Treatment Plant (CSTP). These plants may provide storage, settling after their storage volume is filled, and disinfection of overflows. At the end of the rainfall event, waste remaining in the plant's tanks is routed to treatment along with the dry weather flow. Unless the plants are made quite large, the major benefit is obtained from the available storage volume.

3. Off-Line Storage. Off-line storage facilities may be at a downstream location in the drainage area where sufficient flows are tributary and land is available. Storage basins may be earthen lagoons, covered or uncovered concrete tanks, or below ground storage facilities. In addition to providing storage, such facilities usually include flow diversion structures, pumping facilities, regulating structures, screening facilities and sludge removal or suspension facilities. The construction cost of storage basins has been estimated using data provided by the U.S. Environmental Protection Agency. These costs have been adjusted to reflect current costs. They do not include costs for rock excavation, piles, unusual dewatering conditions, interconnecting sewers, etc. Such tanks may provide cost-effective facilities for pollution abatement. A typical tank is shown in Plate VII-1 and associated Flow Control Module in Plate VII-2.

4. In-Line Storage. In-line storage or collection system storage takes advantage of the volume in the larger diameter sewers for storage. Regulators, level sensors and other appropriate appa-

ratus are installed which allow routing of storm flows. The pipe volume could provide regulation by installing a restricted outlet. In major storms, which do not statistically contribute significantly to pollution, provision is required to open the regulator to permit passage of peak flows. A typical Storm Sewer Storage Module and Combined Sewer Storage Module is shown in Plates VII-3 and VII-4, respectively. Movable crest dams could also be used in a storage module. Controlled storage within an existing combined sewer system could be a viable alternative provided sufficient volume is available. A volume capable of storing the runoff from 0.15 inches of rainfall provides a substantial degree of CSO pollution abatement. Flushing stations to remove settled solids should be provided for each storage site.

Previous studies have investigated the use of an "advanced combined sewer system" which combines flow routing with in-pipe storage provided in over-sized sewers. Such a system makes use of overland flow for runoff for some distance before interception of the runoff in the collection system. The sanitary flow is picked up at the source in small diameter pipes, thereby reducing the cost of the collection system. Storage located to control flow from two- thirds of the area can be as effective as storage located at the furthest downstream point in the area. Such systems appear to have greatest application where new areas are being developed or where the existing system requires extensive replacement.

5. Swirl Separator. The swirl separator is of simple construction and has no moving parts. A cut section is shown in Plate VII-5. The basic construction consists of the following main parts: (a) inlet ramp which introduces the incoming flow at the bottom of the chamber, while preventing surcharges on the immediate upstream sewer, (b) flow deflector which directs flow after completing its first revolution in the chamber to be deflected inwards, (c) scum ring which prevents floating solids from overflowing, (d) overflow

weir and weir plate which carries the overflow to discharge and captures some floatables, (e) spoilers, which reduce rotational energy, thus improving the separation efficiency, (f) floatables trap which stores floatables, (g) foul sewer outlet which directs concentrated combined sewage to the interceptor for treatment, and (h) downshaft which directs the lower concentration, high volume, wet weather flows to the receiving water.

6. Sewer Flushing. Sewer flushing alternatives are an adjunct to, but are not a substitute for, structural facilities to obtain pollutant reduction in the CSO's. Sewer flushing during dry days is more effective in reducing BOD than SS in CSO. Resuspended solids tend to resettle in downstream sewers. With dilute sewage, flushing becomes less effective and may result in greater costs than other alternatives to achieve the same degree of pollution control. The average solids deposition per foot in trunk sewers may be greater than that in lateral sewers. The effectiveness of flushing in larger size sewers needs investigation.

Flushing of selected sewers on a regular basis, along with a program of physical cleaning, should economically insure the continuing capability of sewer laterals and trunks to provide maximum capacity and storage for combined flows. The selected sewers would have normally low velocities that would not maintain sewer solids in suspension during dry weather. Flushing may be expected to wash out significant parts of pollution associated with the organics. Physical cleaning may be required to move sand and grit. A flushing station consists of a manhole containing an hydraulically-operated quick opening gate and a chamber housing air compressors, electrical control system, sump pump and appurtenances. The sewer would be blocked until the desired sewage volume was contained to produce a flushing wave. The sewage would then be quickly released. The volume of sewage impounded during this procedure would be monitored by water elevation to prevent backups into service connections.

Since sewer flushing may be desirable, the relationship of pipe wall shear stress, flow, pipe size and pipe slope was investigated. The analysis assumed steady flow and that the Manning formula applied. Success has been reported in flushing sewers 12 to 15 inches in diameter by maintaining flows of 0.5 cfs for about two minutes to create a wave of celerity. This would indicate that a shear stress equal to 0.04 pounds per square foot could be sufficient for effective flushing. The relationship between shear stress, pipe diameter, flow and pipe slope is shown in Plates VII-6, VII-7 and VII-8. A flow of 0.5 cfs may not be successful in flushing larger sized pipe unless the pipe slope equalled 0.005 or more. At a flushing flow of 1.0 cfs, all pipe sizes up to seven feet with a slope of at least 0.003 might be flushed successfully. At a flushing flow of 1.5 cfs, all pipes up to seven feet diameter and a slope of 0.003 might be suitable candidates for flushing. For a given slope and flow, the shear stress is relatively constant. Hence, large pipes might be flushed successfully with relatively small quantities of water. This could offer aid in cleaning sewers of deposits after wet weather flows have been stored to permit routing combined sewage to treatment.

Costs of sewer flushing based on full-scale operating experience is not available. Estimates are based on automatic flushing equipment and should be verified by field demonstration.

7. Interceptor. Existing or new interceptor capacity upstream of the pumping station may also be used to provide CSO pollution abatement. Flow can be stored in the interceptor until treatment capacity becomes available. Costs and storage methods are the same as for in-pipe storage. Interceptor capacity equal to 10 percent of the peak flow from a design storm with a five-year return frequency might capture for treatment about 90 percent of the pollutants in CSO. However, this would require a peak ratio of about 20 times the DWF.

8. Street Sweeping. Street sweeping is the manual or mechanical cleaning conducted by municipal personnel. Mechanical sweeping is most common. Effectiveness is related to the sweeper efficiency, cleaning frequency, number of passes, equipment speed, pavement conditions, equipment type and public awareness. At present, street sweeping may well be 30 percent or less effective due to equipment limitations and parked cars blocking curbs. Street sweeping also can have high costs.

9. Catch Basin Maintenance. A catch basin is a chamber, usually built at the curbline of a street, which transfers stormwater from the street surface to a sewer or drain. At its base is a sump which retains sediment, grit, surface drainage and organics including leaves, grass, pet feces, etc., below the invert level of the existing outlet pipe. The volume of pollutant contained in the sump is small compared to the total amount available to mix with storm runoff. If not cleaned regularly, the catch basin may introduce pollutant rather than remove it. The catch basin sump may be filled with concrete to eliminate the need for cleaning.

10. Flow Source Control. The general classification of flow source controls covers all other non-structural alternatives. These include the use of rooftops, parking lots, etc., for the storage of rainfall, the use of porous pavement in streets and parking lots to reduce runoff quantities and other methods designed to capture or reduce the effect of surface runoff to upstream locations. These methods appear impractical in a highly developed area where new construction is not expected on a large enough scale to effect significant results.

C. Feasible Alternatives

Because sewer flushing coupled with in-line and/or off-line storage can provide a substantial degree of CSO pollution abatement, the City's sewer system has been analyzed to determine locations where:

1. sewer flushing would be beneficial in limiting dry weather deposits;

2. sewers could be used to provide in-line storage to store flows for diversion to treatment after the rainfall subsides, and

3. locations are available to provide storage tanks.

Sewer flushing stations are defined in Table VII-1; in-line (pipe) storage locations in Table VII-2 and storage tank locations in Table VII-3. Plates VII-9 through VII-28 show the locations of the various tanks. Their construction and operating and maintenance costs were estimated on the basis shown in Chapter IX.

D. Effects of Individual Alternatives

Table VII-4 and VII-5 present the effects of various individual options available for CSO pollution abatement for areas draining to the Westerly and Easterly Interceptors, respectively. The effectiveness of the individual options are described briefly here following.

Area NNW. Upstream storage tanks (above elements 216 and 715) are relatively high in cost per unit of pollutant removed as is the swirl separator. However, these upstream storage tanks would relieve the flooding of streets and cellars with combined sewage. A down-

TABLE VII-1

POTENTIAL SEWER FLUSHING STATIONS

Drainage Area	Location	Sewer Junction
NNW	Elmora & Murray	711
NNW	Grove @ Pennington	717
NNW	Orchard @ Chilton	720
NNW	Orchard @ Morris	723
NNE	North Broad @ Waverly	827
NNE	Newark @ Clinton	830
NNE	Pingry @ Salem	836
NNE	Union @ Oakwood	839
NCE	Jefferson @ Mary	851
NCE	Jefferson @ Chestnut	858
CCN	Catherine, West of CRR N.J.	185
CCN	Reid @ East Grand	201
CCN	Reid @ East Jersey	307
CCS	First @ Sixth	971
CCS	Third @ Niles	974
CCS	Fourth @ Palmer	979
WW	South Elmora @ Lidgerwood	19
WW	Summer @ South Broad	231
NEN	Fanny & Madison	807
NEN	North @ Adams	812
NEN	Van Buren bet. North & Fanny	821
NES	Fairmont @ Henry	321
SE	Livingston @ Sixth	133
SE	Trumbull bet. Sixth & Schiller	901
SSE	Second @ Magnolia	925
SSE	First @ Broadway	935
SSE	Front @ Fulton	955
SSW	Third @ Zamorski	962
SSW	Third @ Geneva	966
SSW	Third @ Loomis	991

TABLE VII-2

POTENTIAL IN-LINE STORAGE LOCATIONS

Area	Module Location	Sewer Junction or Element	Volume (mg)
NNW	Morris Ave. & Union	842	0.79
NNW	South of Sayre St. @ Elizabeth River	182	0.23
NNW	Westfield Ave. @ Elizabeth River	160	1.36
NNE	Morris Ave. @ Union	842	0.26
NNE	North Broad & Newark	833	0.11
NNE	Union & Prince	350	2.05
NCE	Jefferson @ East Jersey	860	0.12
NCE	Elizabeth Ave. @ Scott	660	0.46
CCN	South @ South Spring	225	0.14
WW	Summer @ Bayway Circle	83	0.08
WW	Summer @ Clarkson	760	0.26
NEN	North @ Adams	812	0.20
	Dowd near Alina	820	0.24
NEN	Madison @ Alina	377	0.36
NEN	Jackson @ Alina	401	0.23
NEN	Dowd near Alina	481	0.14
NES	Division near Dowd	27	0.65
SSE	Front St., East of Elizabeth Ave.	960	0.08
SSE	Broadway, South of Front St.	869	0.62
SSW	Third Ave., North of S. Front St.	970	0.21

TABLE VII-3

POTENTIAL STORAGE TANK LOCATIONS

Area	Location	Max. Storage Volume (mg) Considered
NNW	Westfield Ave., opp. Galloping Hill Rd.	3.50
NNW	Crane St. @ Union St.	3.27
NNE	Union Ave. @ Prince St.	1.64
NNE	Union Ave., bet. Morris & Prince	1.64
NCE	Scott Park	1.06
NCW	Pearl St. & South Broad	2.18
CCN	Fourth Ave., bet. South & Center Sts.	2.53
CCS	Fourth Ave., bet. Seventh & John	0.87
WW	Clarkson Ave., bet. Summer & Garden	3.98
NEN	Kellogg Park	1.86
NES	Dowd Ave. & Progress St.	0.89
SE	Trumbull @ First St.	4.44
SSE	Elizabeth Ave. @ South Front St.	1.69
SSW	Third Ave. @ South First St.	1.19
NNW	Baker Pl., bet. Springfield Rd. & Elmora Ave.	1.27
NNW	Carteret Park	1.67
NCW	Caldwell Park	1.75
CCN	Catherine St. bet. East Grand @ CRR N.J.	1.24
SSW	Southwest of Butler & Second	0.96
SE	Trumbull St. & CRR N.J. - Perth Amboy Branch	1.17
SE	Broadway & Seventh St.	2.14
SE	Seventh St., bet. Parkway & CRR N.J.	1.48

stream location for off-line storage (at Crane and Union Streets) should relieve pollutants at about one-third the unit cost of the upstream tanks, but would not relieve the present street and cellar flooding. In-line storage in an existing sewer is low in cost per unit of pollutant removed but, because of the restricted amount of storage available, is limited to divert to treatment less than 40 percent of the pollutants. Sewer flushing is also economical but can only be expected to divert to treatment about 25 percent of the pollutants. On the other hand, a relatively large storage tank located downstream can be expected to remove better than 70 percent of the pollutants. A large sewer, located on Westfield Avenue, receives overflows of combined sewage. By utilizing the storage available in this sewer, almost 50 percent of the pollutants reaching it can be diverted to treatment at a modest cost. If higher degrees of removal are required a combination of options is indicated.

However, each option except the first in a series would remove less pollutant than the individual option since less pollutant would reach it. Since NNW is located farthest upstream and discharges about 20 percent of the City's total wet weather pollutant load, a significant reduction in these pollutants should improve the river water quality.

Area NNE. Variations of five basic options were considered, sewer flushing, in-line storage in combined sewers, downstream off-line storage, a swirl separator and in-line storage in existing large storm drains. Parallel utilization of combined and storm sewers for in-line storage was most economical and could divert to treatment almost 50 percent or more of the pollutants in the wet weather flow. Flushing at two locations was next in least unit cost but could only route to treatment about ten percent of the total pollutants. Off-line storage was next in unit cost but could only route to treatment about 45 percent of the total pollutants. The swirl separator was most costly and would route for treatment only about 30 percent of the pollutants because parts of this acrea are served by a separate system. This area currently contributes about seven percent of the total wet weather pollutant discharges from the City. However, its upstream location on the Elizabeth River could justify a higher degree of pollution abatement.

Area NCE. A large part of this area has been provided with separate storm sewers. However, there are interconnections between the storm and combined sewer systems and about two-thirds of the wet weather pollutants result from the storm sewer discharge. Alternatives considered include sewer flushing at two locations, in-line storage on Jefferson Avenue, off-line storage on West Scott Place, a swirl concentrator and in- line storage in the storm sewer on West Scott Place. Sewer flushing would remove about five percent of the pollutants, and would be relatively costly. In-line storage on Jefferson Street and West Scott Place would be least costly and would direct to treatment about 45 percent of the pollutants. Off-line storage in Scott Place would have somewhat lower unit costs than flushing but could divert to treatment about 30 percent of the pollutants. The swirl separator would be somewhat higher unit costs than off-line storage, but would divert only 17 percent of the pollutants to treatment. A high degree of pollution abatement in this area would require a combination of options.

Area NCW. Only two options are available for this area, off-line storage at Pearl Street and South Broad, and a swirl separator. The off-line storage would direct to treatment about 66 percent of the pollutants at a lower cost per unit of pollutant than can the swirl separator which would only divert about 50 percent. The two options could operate in series if a greater degree of pollution abatement is required.

Area CCN. Options considered included sewer flushing at three locations, off-line storage at Catherine Street, between East Grand

Street and the CRRNJ, for both pollution abatement and relief of the underpass flooding with combined sewage, in-line storage at South and South Spring Streets, off-line storage at Fourth Avenue between South and Center Streets. Sewer flushing has the lowest cost per unit of pollutant diverted but would divert only about 35 percent of the pollutants to treatment. Off-line storage at Catherine Street is costly but may not be excessively so considering its dual function. It could divert to treatment about 45 percent of the wet weather pollutants. In-line storage has low costs per unit of pollutant diverted but could only divert to treatment about 25 percent of the pollutants. Off-line storage at Fourth Avenue has lower costs per unit of pollutant diverted than at Catherine Street and could divert to treatment about 75 percent of the pollutants. The swirl separator has higher unit costs and could remove about 50 percent of the pollutants.

Area CCS. Options available are sewer flushing at up to three locations, off-line storage on Fourth Avenue between Seventh and John Streets and the swirl separator. Sewer flushing would divert to treatment from 25 to 30 percent of the pollutants with the least unit cost alternative being a single station. The off-line storage basin could divert to treatment as much as 80 percent of the pollutants at a higher but not unreasonably so, unit cost. The swirl separator has the greatest cost per unit of pollutant removed.

Area WW. Options considered included in-line storage in combined and storm sewers, sewer flushing at two locations, off-line storage on Clarkson Avenue between Summer and Garden and the swirl separator. Sewer flushing has the least unit cost but could divert to treatment less than 25 percent of the total pollutants. In-line storage is the next lowest unit cost option but could only divert to treatment about 20 percent of the pollutants. Off-line storage costs were reasonable, although somewhat higher in cost per unit of pollutant diverted to treatment, but about 60 percent of the pollutants could be so diverted. The swirl separator has the highest unit cost and would divert to treatment only about 33 percent of the total pollutants.

Areas NCW, CCN and CCS, between them, contribute about 12 percent of the total City's wet weather pollutant discharge (or about 21 percent of that discharged to the Elizabeth River). Area WW, by itself, contributes about the same. The river water quality has been shown to deteriorate at an accelerated rate between Summer and Trenton Avenues and that gross pollution exists from South Street downstream. Accordingly, wet weather pollutant discharges from these areas appear to require attention if the river is to be reclaimed.

Area NEN discharges to the Easterly Interceptor with wet weather overflows to Newark Airport's Peripheral Ditch. The area contains both combined and storm sewers. Options considered include sewer flushing, storage at Kellogg Park for pollution abatement and relief of combined sewage flooding, in-line storage in combined and storm sewers and the swirl separator. Sewer flushing was the least unit cost option. However, it would divert to treatment only about 30 percent of the total pollutants. Storage at Kellogg Park is the highest unit cost option and would only divert to treatment about 30 percent of the pollutants. In-line storage in combined and storm sewers would be moderate in cost and could divert about 47 percent of the pollutants to treatment. The swirl separator is somewhat higher in unit cost than in-line storage but would divert to treatment about 30 percent of the pollutants now discharged.

Area NES also contains both combined and storm sewers. Wet weather overflows discharge to the Great Ditch. Options available are sewer flushing, in-line storage in a storm sewer, off-line storage at Dowd Avenue and Progress Street, and the swirl separator. The least unit cost alternative is in-line storage which would divert about 35 percent of wet weather pollutants to treatment. Sewer flushing is next to lowest in unit costs, but would divert only about eight percent of the wet weather pollutants. Off-line storage has greater unit costs, but is not unreasonably expensive, and could divert about 38 percent of the pollutants. The swirl separator would be highest in unit costs and would divert about 23 percent of the pollutants. The pollutant removed by in-line storage would be additive to that removed by other options.

Area SE is served by a combined sewer system. Its wet weather discharges enter the Great Ditch and the Newark Bay at its confluence with the Arthur Kill and are relatively large, about 14 percent of the City's total. Options considered included off-line storage at Broadway and Seventh Street, which would serve the dual function of relieving combined sewage flooding at Seventh and Court Streets, Sixth and Court Streets, and Trumbull and Seventh Streets and reducing wet weather pollutant discharges; sewer flushing; off-line storage at Trumbull Street and First Street and the swirl separator. Off-line storage (0.74 million gallons) at Seventh Street and Broadway would be reasonable in cost but would divert to treatment only about 35 percent of the total pollutants. Sewer flushing would be very economical and would divert to treatment about 74 percent of the pollutants. Off-line storage at Trumbull and First Streets presents costs per unit of pollutant diverted that are about two-thirds that of storage and Seventh and Court Streets and about ten times that for sewer flushing. It could divert to treatment, however, about 92 percent of the pollutants now discharged. The swirl separator has highest unit costs and would divert to treatment only about half the total pollutants now discharged.

Area SSE contains both combined and storm sewers. Wet weather pollutants now overflow to the Arthur Kill. Options considered include sewer flushing, in-line storage in both combined and storm sewers, off-line storage at Elizabeth Avenue and South Front Street and the swirl separator. In terms of cost per unit of pollutant removed, the order starting from least cost is sewer flushing followed by in-line storage in the storm sewer, off-line storage, in-line storage in the combined sewer and finally, the swirl separator. The percent of total pollutant diverted to treatment by each of the options is:

Option	% Pollutant Diverted
Sewer Flushing	18
In-Line Storm Sewer Storage	20
Off-Line Storage	68
In-Line Storage Combined Sewer	12
Swirl Concentrator	38

A high degree of pollutant diversion to treatment would require a combination of options with the only option directly additive to others individually or in combination being in-line storm sewer storage.

Area SSW is served by a combined sewer system. Wet weather pollutants discharge to the Elizabeth River between South Front and South First Streets and immediately south of Trenton Avenue. The area discharges about five percent of the wet weather pollutants from the City. However, the discharge appears to enter the pollutant sink and in small rainfalls could be washed upstream with the incoming tide. Options considered include sewer flushing, dual-purpose storage for pollution and combined sewer flooding abatement, in-line storage for pollution abatement and the swirl separator. In terms of cost per unit of pollutant removed, the order, starting from least cost, is sewer flushing, in-line storage, off-line storage, dual purpose off-line storage and the swirl separator. The percent of total pollutant diverted to treatment by each of the options is:

Option	% Pollutant Diverted
Sewer Flushing	37
In-Line Storage	37
Off-Line Storage	89
Dual Purpose Storage	73
Swirl Separator	50

While off-line storage can divert a large part of the total pollutants to treatment, a combination of sewer flushing and in-line storage with off-line storage could provide equal benefits at a lower cost.

Area SW includes that part of the City located south of the Turnpike and west of the Elizabeth River. Major industries, including Phelps Dodge Copper Products Co. and Reichold Chemical, and the Joint Meeting Plant are located in this area. The original Joint Meeting Trunk Sewer is located in Bayway. Before construction of the Joint Meeting Plant, the raw sewage of the Joint Meeting municipalities was discharged through this sewer. With the construction of the treatment plant, this sewer was intercepted at Bayway and Pulaski Street. However, the City of Elizabeth continued to use this sewer to discharge highly polluted, untreated, industrial wastes to the Arthur Kill until 1968 when the Bayway Interceptor was constructed. This Interceptor diverted dry weather flow in the 72-inch brick Bayway sewer to the Easterly Interceptor. Wet weather flows still discharge untreated to the Arthur Kill. By providing a level actuated control on the flap valve of the present regulator, most of this flow can be stored and diverted to treatment. The amount of pollutant that would be so treated is as follows:

	Annual Overflow SS (lbs/yr)	BOD (lbs/yr)	Flow (mg/yr)
Existing Condition	13308	4136	1.6
Pipe Storage*Utilized	797	442	0.4

*Volume = 0.34 mg

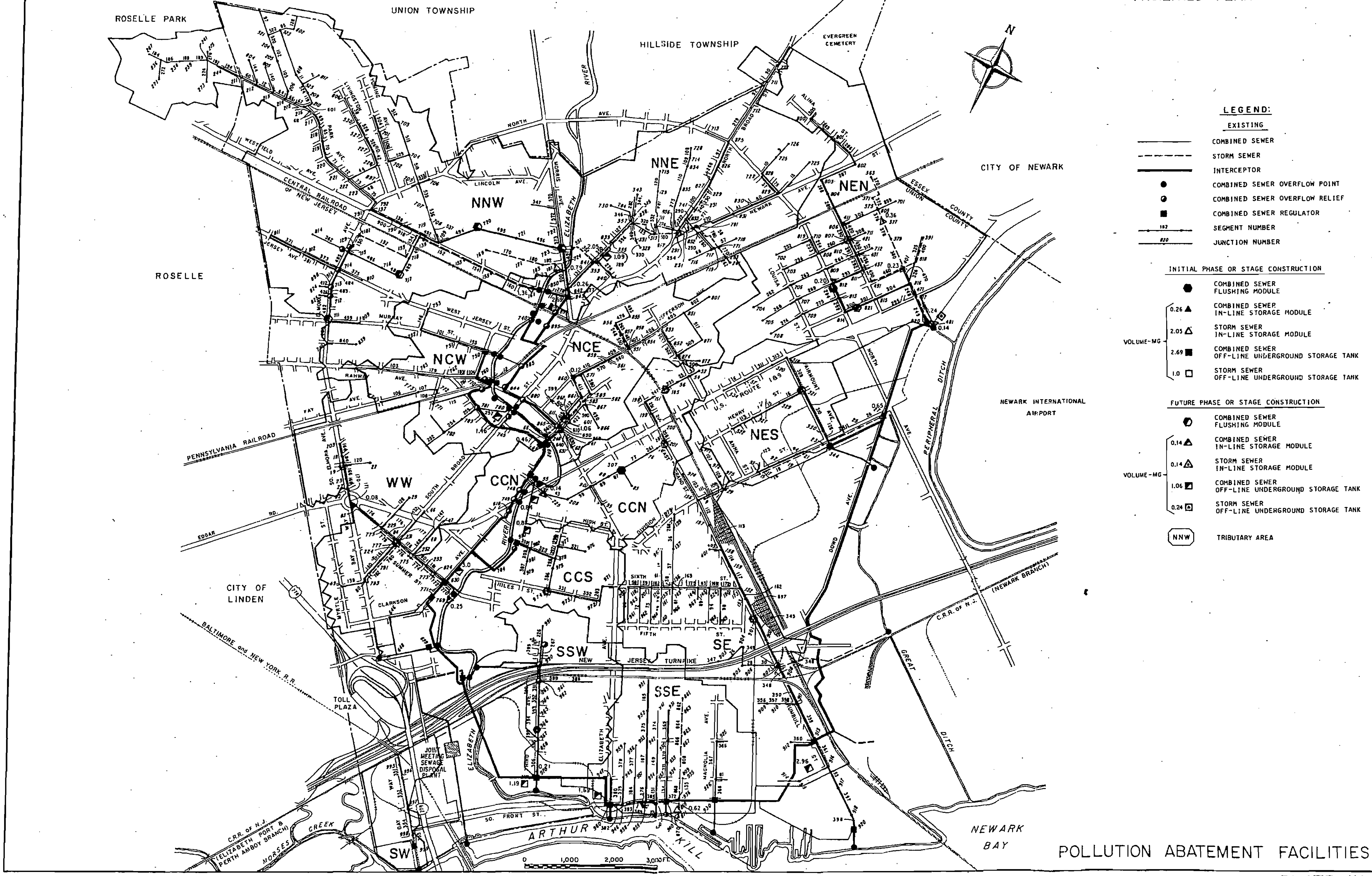
E. Combination of Options for Pollution Abatement

The above discussions consider each option individually. The effects of combinations of options have been analyzed by the methodology previously defined. Tables VII-6 and VII-7 summarize pertinent data upon which the various alternatives for pollution abatement have been analyzed. The facilities included in the various alternatives are coded in the "Area" columns and can be determined by reference to Tables VII-4 and VII-5.

Areas Served by Westerly Interceptor. Table VII-6 lists over 1000 alternatives for diverting to treatment wet weather pollutant overflows, ranging from the present condition to diversion of about 83 percent of the total pollutants presently discharged. The alternatives are combinations of the options presented in Table VII-4. As an example of how the coding is used, the facilities included in case 640 for about 80 percent raw BOD discharge diversion are as follows:

CITY OF ELIZABETH, NEW JERSEY

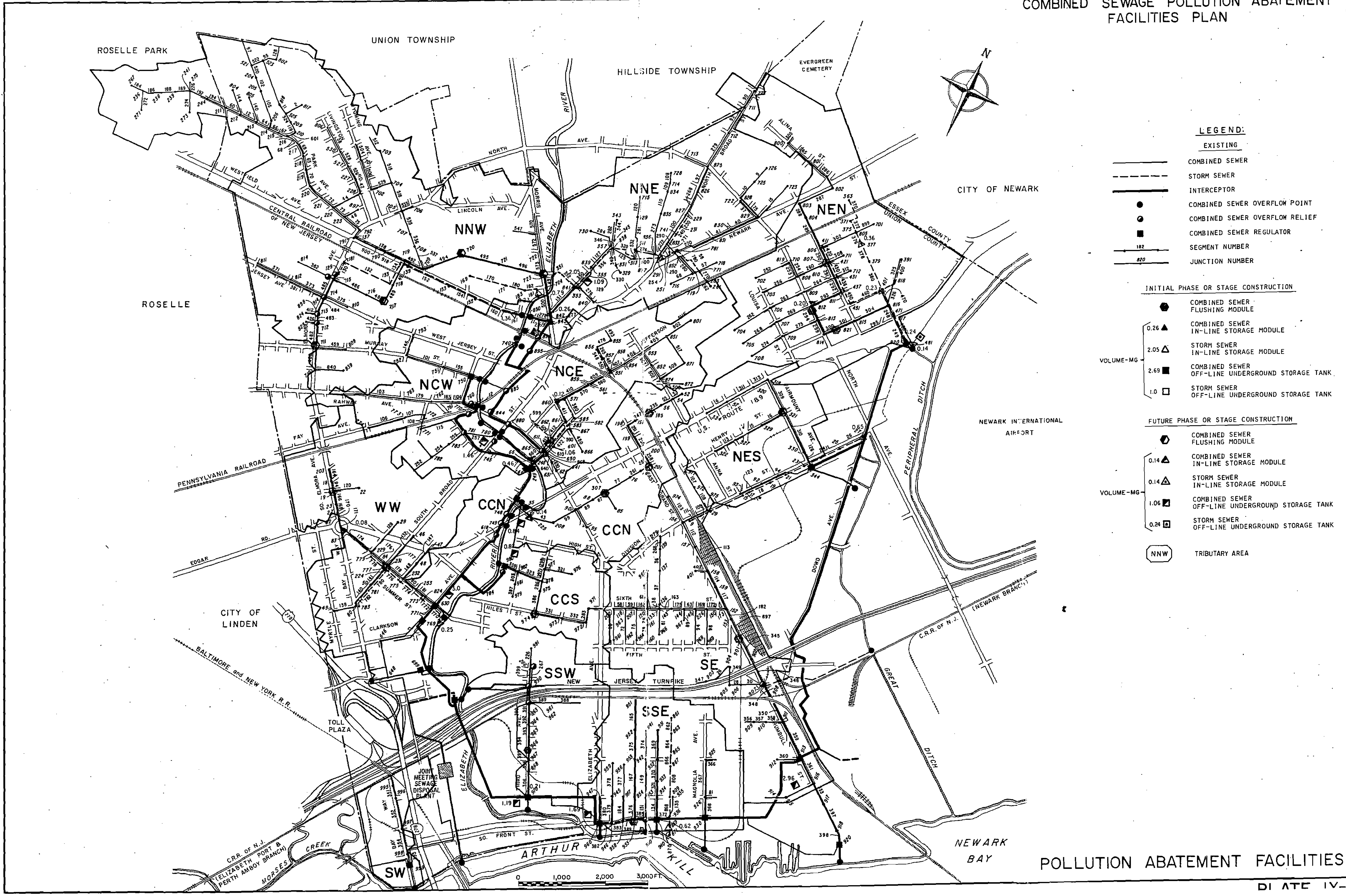
COMBINED SEWAGE POLLUTION ABATEMENT FACILITIES PLAN



POLLUTION ABATEMENT FACILITIES

CITY OF ELIZABETH, NEW JERSEY

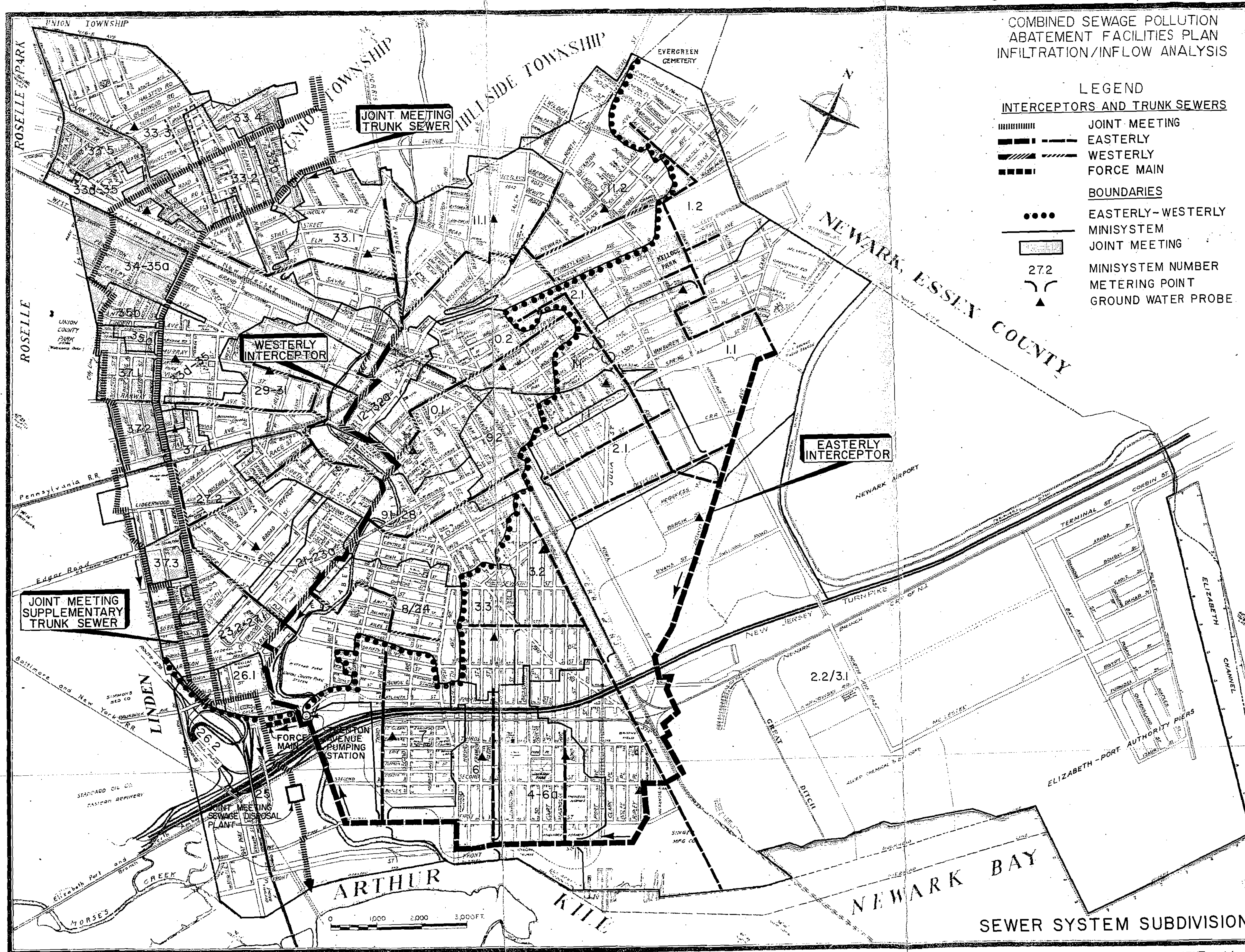
COMBINED SEWAGE POLLUTION ABATEMENT FACILITIES PLAN



POLLUTION ABATEMENT FACILITIES

PLATE IV-1

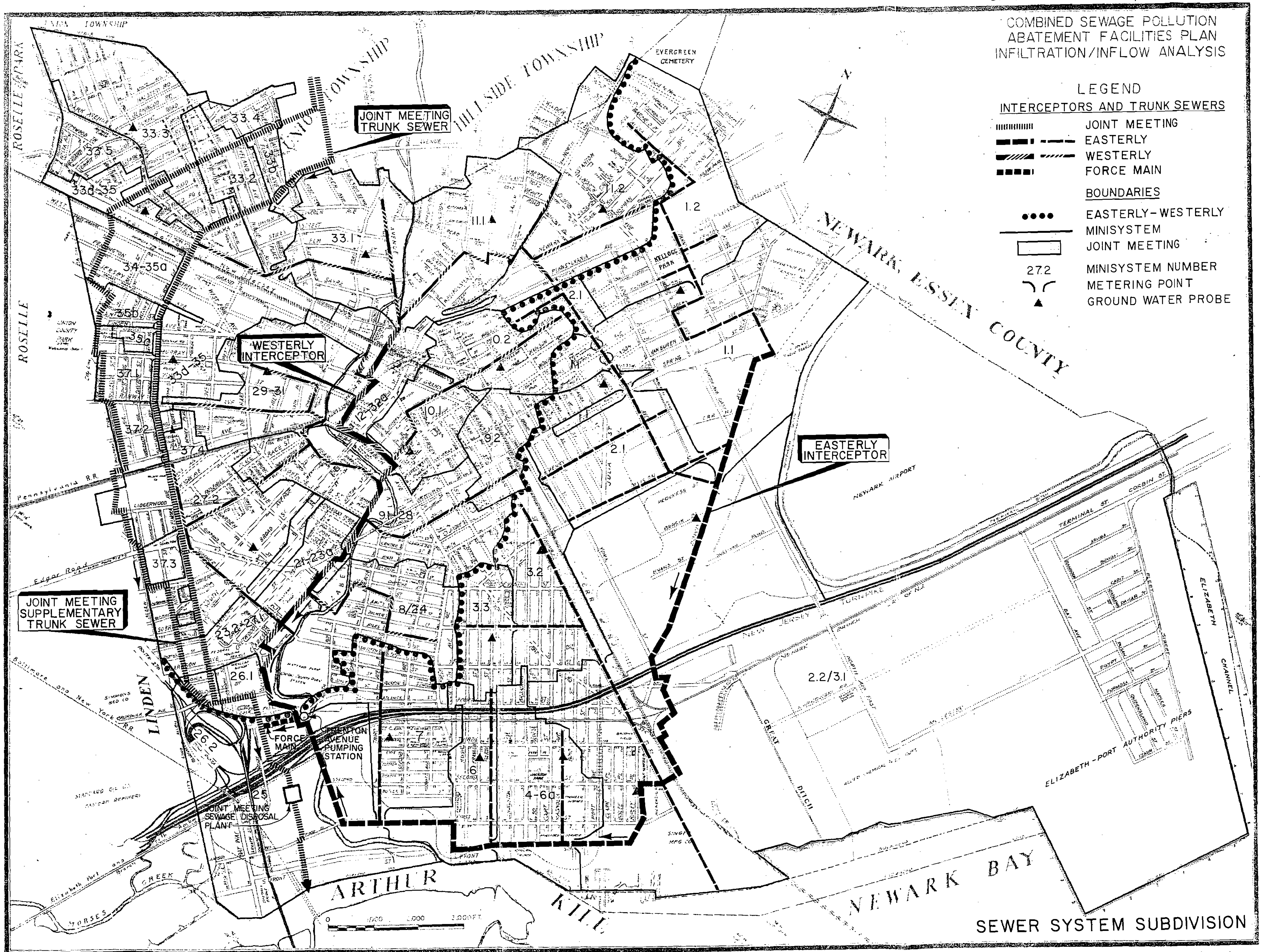
CLINTON BOGERT ASSOCIATES



CLINTON BOGERT ASSOCIATES

PLATE X-1

CITY OF ELIZABETH, NEW JERSEY



CLINTON BOGERT ASSOCIATES

PLATE X-1

20

Report to the City of Elizabeth

Combined Sewage Overflow Abatement Strategy

Solids/Floatables Reduction at Combined Sewer Overflow Points

June, 1993

Clinton Bogert Associates

Consulting Engineers since 1924

LETTER OF TRANSMITTAL

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Consulting Engineers since 1924

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June 15, 1993

Honorable Mayor and Council
City of Elizabeth
City Hall
50 Winfield Scott Plaza
Elizabeth, NJ 07021

Re: CSO Abatement Strategy Report
Solids/Floatables Reduction

Dear Mayor and Council:

The Federal Clean Waters Act (CWA) requires combined sewage overflows (CSO) to comply with technology-based requirements to minimize the impact of CSO on (1) receiving water quality, (2) aquatic biota, and (3) human health. To comply with this Act, the New Jersey Department of Environmental Protection and Energy (NJDEPE) has instituted a phased program which initially requires solids one-half inch and larger to be eliminated from CSO discharges, to be followed by additional steps in a later phase involving either (a) best available practical control technology, (b) best conventional control technology, or (c) best available technology economically achievable.

Transmitted herewith is our Report on the cost-effective works to eliminate the discharge of combined sewage floatables and solids 1/2 inch or greater from the City's 34 outfalls subject to the provisions of NJDEPE combined sewage overflow (CSO) permits. This plan is in compliance with the State's phased implementation of technology-based requirements of the CWA. Where consistent with the objective of preventing the discharge of solids/floatables 1/2 inch or larger in the CSOs, this plan also presents the best available technology economically achievable to (1) maximize the interception of CSO consistent with treatment plant and interceptor capacities, and (2) more effectively utilize in-line storage, previously provided to divert combined sewage to treatment at an acceptable rate.

Excess combined sewage discharges to the waterways via 17 primary, 9 relief and 8 minor outfalls. Upon evaluating the alternatives, optimum strategies are proposed at each type of outfall. Detailed hydrologic studies of 44 years of rainfall data at Newark Airport indicated that a higher degree of treatment for combined sewage generated by rainfalls at a rate of 0.2 inches per hour with lesser treatment for combined sewage from rainfalls in excess of this rate should meet the interim State requirements and facilitate meeting the future ultimate Federal requirements at relatively low cost.

The selected alternative for the primary CSO Outfalls includes: (1) 13 first flush facilities (FFFs) designed to comply with the first phase solids removal, (2) 14 diversion and screening facilities (DASFs) at the consolidated primary outfalls, designed to: (a) divert the majority of CSO volume to 13 proposed downstream FFFs, and (b) screen the less polluted ensuing flows generated by high intensity rainfall.

Auxiliary construction required for the proper operation of the FFF and DASF includes (a) seven new tide gates, (b) 16 remote actuated shutoff gates on DWF interception points, (c) four regulator relocations, (d) modified hydraulic control of four storage module flap gates, and (e) piping for consolidation of adjacent outfalls.

The selected alternative for the nine relief outfalls includes the construction of relief DASFs at the 12 internal relief interconnections, that divert the combined system flow into the adjacent relief system. The relief DASFs would be equipped with vertical separation of the flows and manually cleaned bar screen with 1/2-inch wide openings to capture solids retrofitted into the existing or expanded chamber at the interconnection.

Auxiliary work required for relief outfalls operation includes: (a) modified hydraulic control of four storage module flap gates on relief outfalls, (b) a new barrel for the Morris Avenue siphon, and (c) reconstruction of a demolished East Jersey Street relief outfall.

The proposed work at minor outfalls is separation of the combined sewers to eliminate CSO at each of the eight minor outfalls. About two miles of new storm and sanitary sewer are proposed to be installed. In addition, catch basins directly connected to the interceptor system would be disconnected.

The construction will occur throughout the City in relatively confined areas. Most of the major construction for FFFs is proposed in vacant industrial lots, parking lots and fringes of future parkland. Construction of some of the piping connected to the DASF and FFF, and sewer separations will require detouring of traffic. Most of the proposed work can be constructed without disrupting the present sewage flows. There will be some temporary use of the adjacent property required for construction. Appropriate barricades would minimize the disturbance of the adjacent industries and business, minimize rubbernecking and keep children and vandals off the sites.

The estimated construction cost of the recommended work is $20,690,000 based on 1993 price data. The total project capital cost is $24,759,000. It is assumed that the present program of funding the preparation of Contract Documents through 90 percent grants will be continued under the Combined Sewer Overflow Fund. The City has applied for such grant funding. The requested grant amount is $1,800,000. The remainder of the project costs, $22,679,000, should be funded by low interest loans under the State Revolving Fund.

Based on 1993 costs, the annual operating and maintenance expense would be $590,000. The annual payment by the City, assuming an ad valorem tax increase would equal $2,133,000 based on the annual operating cost, plus the debt service on the project loan. Households would pay $1,261,100 per year. The remainder of the cost would be paid by other taxed entities. The average householder's incremental annual charge is estimated to be $30.52. This is 0.098 percent of the median annual 1993 household income in Elizabeth.

Very truly yours,

CLINTON BOGERT ASSOCIATES

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EXECUTIVE SUMMARY

EXECUTIVE SUMMARY
COMBINED SEWER OVERFLOW
SOLIDS/FLOATABLES REDUCTION

Introduction

The Elizabeth sewer system includes 34 outfalls for which NJDEPE combined sewage overflow (CSO) permits are required and have been issued. Twenty-six discharge to the Elizabeth River, four to Arthur Kill, two to the Great Ditch, and one each to the Newark Airport Peripheral Ditch and Newark Bay. CSO discharges are to comply with technology-based requirements of the Federal Clean Waters Act (CWA). This requires minimizing the impact of CSOs on: (1) water quality, (2) aquatic biota, and (3) human health. Technology-based standards must consider either: (A) best available practical control technology, (B) best conventional control technology, or (C) best available technology economically achievable. To attain this goal, the State has developed a phased implementation strategy. A program to eliminate the discharge of combined sewage floatables and solids 1/2 inch or greater is now being required. This criteria limits the types of facilities to (a) vortex-type separators, (b) fine screens, or (c) settling basins. Storage for a design storm which might be experienced four times per year on average would provide more extensive treatment than is now required, and would entail greater costs for both construction and operation. Subsequent phases may require CSO pollutant reduction, approaching that resulting from primary treatment. The State has provided 90 percent grants to fund municipal reports to investigate and recommend cost-effective plans to meet the goals of the present phase. The NJDEPE has indicated its intent to also provide 90 percent grants for the preparation of contract documents of facilities described in approved plans.

Problems, Needs and Objectives

Where consistent with the objective of preventing the discharge of solids/floatables 1/2 inch or larger in the CSOs, this plan also presents the best available technology economically achievable to (1) maximize the interception of CSO consistent with treatment plant and interceptor capacities, and (2) more effectively utilize in-line storage, previously constructed, to divert combined sewage to treatment at an acceptable rate. The proposed work must provide for (A) equipment reliability, (B) flexibility and compatibility with possible future CSO abatement phases, (C) limiting capital and operating costs, and (D) mitigating environmental disruption. The plans proposed are to conform to the rules and regulations of (i) USEPA and NJDEPE for CSO abatement strategy, (ii) the NJDEPE Coastal Resources Division, for work in flood plain or fringe, (iii) COE, for work along the Elizabeth River and Arthur Kill, (iv) The State and County Highway Departments, (v) Amtrak and Conrail, (vi) Bi-County Soil Conservation District, regarding excavation, (vii) Elizabeth Zoning Board, and (viii) EUJM, regarding the quantity of intercepted flow.

Existing Setting and Conditions

The 11.7 square mile City of Elizabeth, the Union County Seat, contains about 110,000 residents and extends to tidal Newark Bay and Arthur Kill. Land use in low lying eastern Elizabeth is industrial. Port Elizabeth and Newark Airport are located immediately northeast of the developed urban area. The central and western sections of the City are separated by the Elizabeth River. These sections include a mix of urban residences, commercial developments, institutions and light industry.

Sewage Treatment. All sanitary sewage, and limited rates of combined sewage and urban drainage, from Elizabeth are conveyed to the regional Essex/Union Joint Meeting (EUJM) Treatment Plant in southeastern Elizabeth. Treated plant effluent discharges to Arthur Kill. In 1992, flows from Elizabeth constituted about 25 percent of the average 66 mgd EUJM Plant flow. About 91.5 percent is pumped to the EUJM Treatment Plant by Elizabeth's Trenton Avenue Pumping Station (TAPS); the remaining 8.5 percent of Elizabeth's sewage, from the Elmora section, enters the EUJM Trunks by gravity. By Contract Agreement the peak rate of flow that TAPS may discharge to the EUJM Plant is 36 mgd. However, the CWA requires as much combined sewage as possible for effective treatment to be delivered to the EUJM Plant

Intercepting System. Municipal gravity interceptors convey the City's sewage to TAPS. The 2.2-mile Westerly Interceptor serves the central and western parts of the City, and generally following the Elizabeth River. The 4.0-mile Easterly Interceptor along Arthur Kill and the northeastern tidal ditches serves the southern and eastern parts. The Westerly Interceptor capacity is sufficient to convey maximum dry weather flow (DWF) rates, while the Easterly Interceptor can convey about three times the maximum DWF rate. Plates 5a and 5b show the interceptors.

Collection System. There are about 120 miles of intercepted sewers in the City's collection system, excluding building connections. This includes combined sewers that discharge the storm runoff and sanitary wastes in the same pipe, and separate sanitary sewers.

System Improvements. During the 1950s and 1960s, the City installed several relief and separate storm sewers, to eliminate frequent flooding. Relief sewers have one or more upstream interconnections that permit surcharged combined sewers to overflow into the relief sewers. During the late 1970's and early 1980's, the U.S. Corps of Engineers (COE) abated serious Elizabeth River flooding by increasing the flow capacity of the River. In the 1980's the City implemented phases of their "CSO Pollution Abatement Program" constructing: (a) capacity increases in the Westerly Interceptor, (b) 13 in-line storage modules with regulated interception on sewers with substantial in-line storage capacity, (c) 11 flushing modules that reduce the discharge of settled solids to the waterway during CSO events.

CSO Interception Limitation. During moderate rainfall, the City's combined sewage flow rates, substantially exceed: (a) the capacity of the interceptors, (b) the capacity of TAPS, or (c) the effective treatment capacity of the EUJM Treatment Plant. It is necessary to limit the rate of combined flow entering the interceptor at each point of combined sewage interception. Excess combined sewage discharges to the waterways via 34 permitted outfalls classified herein as primary (17), relief (9), and minor (8). Tide gates on most outfalls prevent the interception of waterway flow.

Primary Outfalls. Primary outfalls serve significant drainage areas, and overflows a dry weather flow (DWF) diversion dam and discharges to the waterway when the capacity of the regulated interception connection is exceeded. Table 2.2.1 lists the 17 primary outfalls along with their: (1) discharge waterway (2) outfall sizes, (3) drainage areas, (4) in-line storage capacities, and (5) flushing modules.

Relief Outfalls. Relief outfalls primarily discharge separate storm runoff, and discharge combined sewage only during higher intensity rainfall when the upstream flow levels in the adjacent combined sewers rise to the level of interconnections. Table 2.2.2 lists the nine relief outfalls along with: (1) the adjacent primary system relieved, (2) outfall sizes, (3) tributary separate areas, (4) in-line storage capacities, and (5) method of interception.

Minor Outfalls. Minor outfalls serve relatively small, or partially separated drainage areas, and discharge when the capacity of the regulated interception connection is exceeded. Table 2.2.3 lists the eight minor outfalls to the Elizabeth River that are intercepted by the Westerly Interceptor, along with their diameters and partially separated service areas. These minor outfalls may more readily be separated than outlet-controlled.

Present CSO Interception Regulation. Due to obsolescence, many of the float operated gates that limited the flow into the interceptor have been abandoned or removed. Fixed orifices, which permit a wide range of intercepted flows based on hydraulic gradient, and vortex valves, which provide a more constant discharge, now regulate flows into the interceptor. At several in-line CSO storage facilities, normally open shutoff gates on the interception connection automatically shut when storage volume is filled and the flap gate opens to discharge stored combined sewage to the waterway.

Technical Basis for the Proposed Work

CSO Characteristics. A study relating combined sewage pollutant concentrations demonstrated:

1. The excess BOD_5 loadings in combined sewage associated with rainfall is highly variable. The maximum BOD_5 loading can exceed three times the BOD_5 resulting from the DWF.

2. Greater loadings and concentrations are associated with small rains following dry periods than with subsequent larger rainfalls. There is a distinct first flush effect.

3. There appears to be a negligible increase in BOD_5 discharge associated with runoff after 2.0 inches of rain have fallen, indicating that runoff from the first 2.0 inches of rainfall cleans the streets and sewers of most pollutants.

Rainfall Intensity Distribution. Neglecting losses, combined sewage rates are proportional to rainfall intensity. Historically, the hourly rainfall intensity distribution is highly skewed. The maximum hourly intensity exceeded 2.0 in/hr, once in 44 years. However, in 89 percent of all rainfall events no hourly intensity exceeded 0.40 in/hr, and in 70 percent of the events no hourly intensity exceeded 0.20 in/hr.

Initial Rainfall Intensity. The first flush results from the initial rainfall which usually is of low intensity. Based on all rainfall events of more than 0.06 inch, 92 percent of the initial hourly intensities are less than 0.20 in/hr, and 94 percent of the average intensities over the initial two hours, less than 0.20 in/hr. For the relatively few rainfalls with initially high intensity, the flushed pollutants are diluted by the runoff volume.

Implications. The cost and land requirements of CSO solids intercepting facilities are dependent on the capacity of the units. Based on the intensity distribution, and the associated CSO loading distribution, the optimum cost-effective solids reduction would be achieved with a two-element facility. One element, a first flush facility (FFF), would treat the first flush pollutants most effectively, and the second, a diversion and screening facility (DASF), would satisfactorily treat the less polluted subsequent flows.

Alternatives

Initial Evaluation. Screening, and vortex systems were evaluated for use as FFFs at primary outfalls. Screening alternatives eliminated during preliminary and secondary evaluation included: (1) mechanically cleaned bar screens, (2) cylindrical mechanically cleaned fine screens, (3) hydrasieves, (4) micro-screens, and (5) belt screens. Reasons for elimination included: (a) potential for clogging, (b) ineffectiveness in intercepting solids 1/2 inch or larger, (c) excessive solids disposal costs, (d) unreliability (e) excessive land requirements and capital costs (f) complexity, (g) costly cleaning and maintenance, and (h) potential structural problems. The surviving alternatives, the swirl separator and rotating drum screen were compared in detail in the final evaluation.

Vortex Type Separators. Vortex separators, of which the swirl separator is in the public domain, are solids settling and concentrating systems with no mechanical equipment to maintain that are suited to intercept first flush solids. At flow rates below design capacity their performance improves. Preliminary debris screening is not required. Swirl separators are circular tanks with diameter to depth ratios of about 4 to 1. The tangential entry of the pumped FFF influent generates rotational currents that concentrate settleable solids into an eccentric floor channel that discharges to the foul outlet for interception. To limit flow rates to the interceptor, vortex valve regulators restrict foul outlet flow rates to the maximum DWF, and automatic shutoffs are installed in the DWF connection upstream. Floatables are concentrated in surface traps and drain to the foul outlet when the storm ends. At low flow rates all floatables should be contained in these traps. Clarified FFF effluent overflows a circular surface weir and discharges through a vertical center pipe. At design flows, occurring on average 24 times per year, a few floatable plastic wrappers, containers and bags, condoms, and small food bags may overtop the weir. A ring of vertical rectangular bars between the weir and the center effluent pipe is provided to prevent their discharge to the waterway. At the sites proposed for FFFs listed in Table 5.2.1, enclosing the swirl separator in a superstructure is not required. A screen security fence should suffice.

Rotating Drum Screens. Self-cleaned rotating drum screens are less costly than other mobile screens. The drum screen is a partially immersed perforated hollow cylinder with a diameter twice its width, supported by central spokes radiating from a horizontal axis. A motor rotates the drum. Pumped influent flow discharges outwardly through the screen 3/8 inch or smaller perforations that form the drum's periphery. The vertical rotation lifts solids trapped along the inner periphery out of the flow where solids are jet washed and mechanically scraped into hoppers in a slurry suitable for interception. The only intercepted flow would be the screen washwater at rates ranging from 0.05 to 0.2 mgd. Some form of self-cleaning trash rack is required upstream of the drum screen as protection from large debris. Special maintenance systems are required to prevent clogging with oil, or organic growth, and corrosion. A ventilated superstructure with suitable provisions for maintenance and odor control would be needed to cover the drum screens.

Final Evaluation. When evaluated by technical, environmental, and economic criteria, FFFs with swirl separators have clear advantage over rotating drum screens. Both systems should capture CSO solids and floatables 1/2 inch or larger before discharge. Tests have shown screens with apertures 1/4 inch or greater will intercept only about 1 percent of the total solids. The swirl separator can reduce the discharge of screenable solids to a degree approaching primary treatment during more highly polluted flows such as expected in the first flush, and may be more readily integrated into subsequent phases of the State's CSO abatement program. The drum screen requires a superstructure and systems of ventilating jet washing, screen scraping and ultraviolet exposure. With no moving parts, the swirl separator requires less maintenance. Estimated project capital costs with swirl separators are $7,189,000 less, and annual operating costs $270,000 less, than with rotating drum screens. The swirl separator alternative is cost-effective, and is accordingly recommended.

Proposed Facilities at Primary Outfalls

The selected alternative for the 17 existing primary CSO Outfalls includes:

(1) 13 first flush facilities (FFFs) at sites listed in Table 5.2.1, complete with access, utilities, controls, helical pumps, swirl separators and regulated foul outlets, along with,

(2) 14 diversion and screening facilities (DASFs) at the consolidated primary outfalls, complete with access, baffles, dams, bar screens, FFF influents and effluents, that: (a) divert the first

flush of the CSO volume to 13 proposed downstream FFFs, and (b) screen a portion of the less polluted ensuing flows generated by high intensity rainfall.

(3) Auxiliary construction required for the proper operation of the FFF and DASF including:

(a) 14 sets of DASF connections to the primary outfalls,

(b) seven tide gates, where required by elevation and unusable existing tide gates,

(c) 16 remote actuated shutoff gates on DWF interception points to prevent overloading the capacities of the interceptors or TAPS when the foul outlets are discharging,

(d) four DWF regulator relocations at Outfalls 001, 002, 037 and 040, and other interfering utility pipe relocations, to accommodate the FFFs and DASFs,

(e) modified hydraulic control of four storage module flap gates upstream of Outfalls 001, 005, 027 and 035 to prevent overloading the FFF, and

(f) piping for consolidation of adjacent Outfalls 005 and 006, and 010, 011 and 013 to single outfalls, and Outfalls 027 and 040 to a single FFF, relocations of Outfall 010 and 027.

These are described briefly hereinafter, and are fully defined in the body of the Report.

Primary Outfall Facility Elements

The CSO discharged from the primary CSO outfalls would be subject to solids/floatable interception in two parallel elements, (1) an FFF with helical pumps and a vortex type separator to provide optimum interception of solids/floatables in flows generated by the initial rainfall period; and (2) DASF to divert flows to the FFF and intercept solids/floatables in the less polluted flows generated by the subsequent rainfall of increments of intensity greater than that normally generating the first flush.

Capacities and Usage. With proposed FFF capacities ranging from 6-to-56 mgd, limited to the runoff developed by a rainfall of 0.20 in/hr plus the maximum dry weather flows, about 85 percent of the runoff flow and 94 percent of the first flush flow could be diverted through FFFs. On average, the FFF would be in use during parts of 84 days per year, though only about 25 days at capacity. The parallel DASF capacities ranging from 28-to-84 mgd will equal the capacity of the upstream system, in case a power or mechanical failure disables the helical pumps, the only mechanical equipment in the FFF. On average, the DASF screen would be in use during parts of 23 days per year. Generally, flows through the DASF screen would be at a much lower rate than the screen capacity.

Flow Route. From a diversion manhole to be constructed on the existing outfall downstream of the point of DWF interception, all CSO would be diverted into the DASF upstream of the screens. From there, the FFF influent would flow into the FFF pump well to be pumped to the swirl separator that has two outlets. The solids laden foul outlet would pass through a vortex regulator and discharge by gravity to the interceptor. The clarified swirl separator effluent would return to the existing or relocated outfall either directly or through the DASF under the screen, joining with any flow through the DASF screen. DASF effluent would discharge by gravity to the outfall sewer, and in most locations pass through an existing or new tide gate, prior to discharging to the waterway.

Sites. The FFF and DASF must be near the primary outfall and interceptor to which they connect. Existing adjacent development limits the FFF and DASF sites to parking lots and vacant lots along the Elizabeth River, Arthur Kill and the eastern waterways; and, in two cases, to small land areas planned as a part of future parklands. Maintenance access is required at all proposed FFFs and DASFs. The DASF can be located completely underground, and be accessible through maintenance openings.

FFF Influent Pumping. Due to the hydraulics of the system low head pumping of the FFF influent is required to route the CSO through the swirl separator and back to the outfall, at all the proposed FFFs. The pumps will permit the FFF to discharge clarified effluent to the waterway concurrent with the Spring high tide elevation. Twin helical pumps ranging from 30-to-66 inches in diameter are provided, that will match the influent flow up to the design capacity, The pumping structure includes the subsurface pump feed well, the pump channel and the above ground effluent channel and motor support, and ranges in size from 35-by-11 feet to 62-by-22 feet. A roof deck with ample ventilation would be provided over the helical pump channels to reduce thermal movement. The electrical control would be contained in surface level cabinets.

Swirl Separator. The proposed swirl separator tanks range in internal diameter from 12-to-31 feet. The tops of the tanks range from several feet above grade at low lying sites to slightly above grade at higher sites. A cover with suitable access openings may be installed over the separator tank.

Interception. All swirl separator foul outlet flow would discharge to the interceptors by gravity. The length of the proposed interceptor connectors varies from 30-to-600 feet. To limit TAPS flow to 36 mgd, proposed vortex valve regulators, in chambers adjacent to the swirl separator, would provide a relatively constant interception rate equal to the maximum DWF.

Diversion and Screening Facilities (DASF). The DASF allows an alternative flow route for (1) the increment of flow in excess of FFF capacity during normal operation, and (2) all the flow, should a power or pump failure be experienced. The DASF will house a baffle, a dam and a manually cleaned bar screen. The baffle and dam, will (a) induce floatables and solids in the excess flow toward the FFF influent, and (b) prevent flows less than the FFF influent capacity from overflowing through the screens. The manually cleaned screens with 1/2 inch openings are provided to intercept solids and floatables this size or larger from the less polluted increment of flow in excess of FFF capacity, normally after the highly polluted first flush has been diverted. Manually cleaned bar screens are to be used in the DASF, due to: (1) the relative infrequency of usage, (2) the greater infrequency of operating at capacity, and (3) the lower concentration of solids/floatables reaching the screen. The proposed DASFs range in size from 31-by-14 feet to 19-by-6 feet.

Outfall Connections. Two large DASF diversion manholes on each existing outfall downstream of the DWF interceptor connection are required to divert all CSO to the DASF and receive the DASF effluent. The section of outfall between the manholes would be plugged.

Tide Gates. New tide gates will be required on the outlet of seven proposed DASFs to prevent tidal waters from overtopping the DASF dam, and being intercepted by the FFF. Existing tide gates can be utilized in several locations.

Upstream Interception Shutoffs. To prevent interception of combined flow from two sources in the same subsystem during rainfall, remote operated shutoffs would close the DWF interceptor connection, when flow in the swirl separator reaches a preset level.

Regulator Relocations. The regulator diverting dry weather flow to interception must be upstream of the DASF connections to the outfall, to keep dry weather flow out of the FFF. This constraint requires the relocation of four existing regulators to upstream locations.

Module Modifications. At four primary outfalls with storage modules upstream of the DASF connections, the control system for the flap gate would be modified to open and close incrementally in response to changes in upstream storage level. These modifications are required to (1) prevent exceeding the FFF capacity, (2) intercept more of the stored combined sewage, and (3) prevent the release of shock loads to the waterway.

Consolidations. Along the Elizabeth River flume, it is cost effective to treat all the CSO generated by Outfalls 005, 006, 010, 011 and 013 at two joint FFF and DASF sites near Outfall 005 and relocated Outfall 010. It also is cost effective to divert the first flush from primary Outfalls 027 and 040 to a single remote joint FFF north of Outfall 027.

Outfalls to Waterways. New outfalls to the Elizabeth River are proposed where primary Outfalls 010 and 026 are to be relocated. Appropriate rip-rap protection of the watercourse around the headwall would be provided as required.

Proposed Work at Relief Outfalls

Relief DASFs. The selected alternative for the nine relief outfalls includes the construction of relief DASFs at the 12 interior relief interconnections listed in Table 5.5.1, that divert the combined system flow into the adjacent relief system. The relief DASFs would be equipped, with vertical separation of the flows and manually cleaned bar screen, with 1/2 inch wide openings to capture solids retrofitted into the existing or expanded chamber at the interconnection. Table 5.5.1 lists the location, sizes and estimated flows.

Auxiliary Work. Auxiliary work required for relief outfalls operation includes: (a) modified hydraulic control of four storage module flap gates at relief Outfalls 003, 036, 041 and 042, (b) a new barrel for the Morris Avenue siphon at Outfall 041 and (c) reconstruction of demolished relief Outfall 030.

Module Modifications. At four relief outfalls with storage modules downstream of the points of interception, the control system for the flap gate would be modified to open and close incrementally in response to changes in upstream storage level. These modifications are required to (1) intercept more of the stored sewage, and (2) prevent the release of shock loads to the waterway.

Morris Avenue Siphon Enlargement. This siphon would be enlarged to prevent excessive use of relief Outfall 041, and deliver FFF design flows from west of the Elizabeth River to the FFF at downstream primary Outfall 005.

Outfall 030 Reconstruction. Relief Outfall 030 has been partially removed, blocking any relief for Outfall 029. Outfall 030 to Arthur Kill near the marina would be reconstructed under this project. Appropriate rip-rap protection of the watercourse around the headwall would be provided.

Proposed Work at Minor Outfalls

Separation. The selected alternative is separation of the combined sewers to eliminate the discharge of CSO at each of the eight minor outfalls listed in Table 2.2.3. About two miles of new storm and sanitary sewer are proposed to be installed. In addition, there are catch basins directly connected to the interceptor system, several along the downstream Westerly Interceptor. Disconnection of these catch basins and re-routing of their flow to a storm system or the river is proposed in order to be able to allocate more interceptor and TAPS capacity for regulated flow.

Environmental Concerns

The construction will occur throughout the City in relatively confined areas. As listed in Table 5.2.1, most of the major construction for FFFs is proposed in vacant industrial lots, parking lots and fringes of future park-land. Construction of some of the piping connected to the DASF and FFF, and sewer separations will require detouring of traffic. Most of the proposed work can be constructed without disrupting the present DWF flow path. There will be some temporary use of the adjacent property required for construction. Appropriate barricades would minimize the disturbance of the adjacent industries and business, minimize rubbernecking, and keep children and vandals off the sites.

Costs and Implementation

Construction Cost. As developed in Tables 6.1.1a and summarized in Table 4.4, the 1993 construction cost of the recommended CSO work; including 13 FFFs with swirl separators and 26 DASFs with bar screens and baffle dams is $20,690,000. If the swirl separators in the 13 FFFs were replaced by rotating drum screens as an alternative, the cost would be about $26,680,000, as developed in Table 6.1.1b. The construction cost estimates include a 20 percent contingency allowance.

Total Project Costs. The total project costs include (1) construction cost, (2) permit applications and BMWAE and SED coordination, (3) surveys and borings, (4) engineering design and contract documents, (5) legal, administrative and fiscal, and (6) construction administration services. The estimated total project cost is $24,759,000,

Project Funding. It is assumed that the present program of funding the preparation of Contract Documents through 90 percent grants will be continued under the Combined Sewer Overflow Fund. The requested grant amount is $1,800,000. The remainder of the project costs, $22,679,000 would be funded by low interest loans under the State Revolving Fund.

Operating Costs. The 1993 annual operating and maintenance costs for electric power, equipment, water, heating and ventilating, maintenance labor, equipment maintenance, supplies and parts, debris disposal and a 10 percent allowance for contingencies, would be $590,000.

Incremental Charge Increases. The annual payment by the City would equal $2,133,000 based on the annual operating cost, plus the debt service on the project loan with 3.0 percent interest and 20-year payback. Households, constituting 59.12 percent of the City's tax base would pay $1,261,100 per year, assuming an ad valorem tax. The remainder of the cost would be paid by other taxed entities. Based on 41,315 households in the City, the average household incremental annual charge is estimated to be $30.52. This is 0.098 percent of the median annual 1993 household income of $31,000 in Elizabeth.

Permits. The City will require the following NJDEPE Permits: (1) Construction and Connection (TWA), (2) Stream Encroachment, (3) Waterfront Development, (4) Dewatering, (5) Wetlands, and (6) renewal of the discharge permit. In addition, permits will be required from the County and State Highway Departments, County Park Department, Conrail and Amtrak, Somerset-Union Soil Conservation District, U.S. Corps of Engineers and N.J. Department of Community Affairs.

SECTION 1
INTRODUCTION

SECTION 1

INTRODUCTION

1.1 Reasons for Report

The Elizabeth sewer system includes 34 outfalls that are subject to the provisions of New Jersey Department of Environmental Protection and Energy (NJDEPE) combined sewage overflow (CSO) permits. In response to recent regulations prohibiting the discharge combined sewage solids/floatables 1/2 inch or larger, the City of Elizabeth authorized Clinton Bogert Associates to prepare this Report that defines a cost-effective plan to comply with the regulations at each outfall. The Report is funded by a 90 percent NJDEPE Grant, and its scope has been pre-approved by the NJDEPE. This program defined herein is a further stage in complying with the United States Environmental Protection Agency's (USEPA) National CSO Control Strategy, and with recent NJDEPE requirements, and represents an additional step that the City is undertaking to reduce pollution from its CSO outfalls.

1.1.1 Regulatory Requirements. CSO discharges from the City's 34 outfalls are to comply with technology-based requirements of the Federal Clean Waters Act (CWA). This requires minimizing the impact of CSOs on: (1) water quality, (2) aquatic biota, and (3) human health. Technology-based standards must consider either: (A) best-available practical control technology, (3) best conventional control technology, or (C) best available technology economically achievable.

To attain this goal, the State has developed a phased implementation strategy. The City has complied with the initial phase prohibiting the discharge of all dry weather waste flows. A program to eliminate the discharge of all combined sewage floatables and solids 1/2 inch or greater is now being required. This criteria limits the types of facilities to (a) vortex-type separators, (b) fine screens, or (c) settling basins. Storage for a design storm which might be experienced four times per year on average would provide more extensive treatment than is now required, and would entail greater costs for both construction and operation. Subsequent phases, now in the process of being defined, may require CSO pollutant reduction, approaching that resulting from primary treatment.

1.1.2 State Grants. To expedite the implementation of the solids/floatables discharge prohibition phase of the CSO program, the State has provided 90 percent Grants to fund municipal reports to investigate and recommend cost-effective plans to meet the goals of the present phase. In 1991, the City applied for, and was awarded a 90 percent planning grant to prepare this Report. The NJDEPE also offers

90 percent design Grants for the subsequent engineering design of, and preparation of Contract Documents for, these facilities. In March 1993, the City applied for the design grant to prepare the Contract Documents.

1.1.3 Ongoing CSO Abatement Program. Based on a Consent Agreement, the City has been engaged in an ongoing program to abate pollution from its CSO Outfalls. Eliminating the discharge of CSO solids/floatables 1/2 inch or larger constitutes the third phase of the program. The initial construction phase included the 1986-88 construction of facilities under Contract 17 that: (1) eliminated dry weather overflows by increasing interceptor capacity, and (2) intercepts the first flush of combined sewage with two storage modules. The second phase included the 1988-90 construction of facilities under Contract 21 that: (1) prevents the build up of settled solids in the combined sewer trunks with 11 flushing modules, and (2) intercepts the first flush with 11 storage modules. The need for this construction was defined in the City's 1981 CSO Abatement Plan.

1.2 Scope and Objectives of Report

This Report meets the City's need to define an affordable program that will abate the discharge of CSO solids/floatables 1/2 inch diameter or larger, with an eye toward the long-term CSO control required to meet water quality standards.

1.2.1 Extent of Report. The Report includes background material, technical design bases, discussion and evaluation of the alternatives, a recommended plan to improve CSO interception, a preliminary cost estimate and an implementation schedule.

1.2.2 Limits of Investigation. Alternatives examined in detail consisted of proven, affordable technologies that could be implemented at the existing outfall sites and are limited to combinations of: (1) screening, (2) vortex separation, (3) interception control, (4) in-line storage control and (5) separation of minor outfalls. Investigation of experimental technologies, such as floatables netting, or costly facilities, such as off-line storage, are beyond the scope. The preliminarily design of facilities proposed herein define: (1) site, capacity and hydraulic requirements, (2) functional goals, and (3) costs. Detailed design of the facilities and the development of construction contract documents are deferred to the subsequent phase.

1.2.3 Primary Objective. The primary objective of this Report is the development of a cost-effective plan to prevent the discharge of CSO solids/floatables 1/2 inch or larger from the outfalls. The proposed work must also provide for: (1) equipment reliability, (2) flexibility and compatibility with possible future CSO abatement phases, (3) limiting capital and operating costs, and (4) mitigating environmental disruption.

The plans proposed are to conform to the rules and regulations of the following agencies:

(a) USEPA and NJDEPE for conformance with CSO abatement strategy,

(b) NJDEPE Coastal Resources Division, for work in flood plain or fringe,

(c) United States Corps of Engineers (COE), for work along the Elizabeth River and in Arthur Kill,

(d) The State and County Highway Departments, where proposed work affects their property or operation,

(e) Amtrak and Conrail, where proposed work affects their property or operation,

(f) Somerset-Union Bi-County Soil Conservation District, regarding excavation,

(g) Elizabeth Zoning Board, regarding above grade structures, and

(h) Essex-Union Joint Meeting (EUJM), regarding the quantity of intercepted flow.

1.2.4 Secondary Objectives. Where consistent with the objective of preventing the discharge of CSO solids/floatables 1/2 inch or larger, this plan also presents the best available technology economically achievable to meet the following objectives consistent with the City's long-term CSO pollution reduction goals:

(1) maximizing the interception of CSO consistent with treatment plant and interceptor capacities,

(2) more effectively utilize in-line storage diverting combined sewage to treatment at an acceptable rate and prevent the rapid evacuation of stored first-flush, and

(3) reducing the discharge of solids/floatables smaller than 1/2 inch.

1.3 Organization of Report

The text of this Report is preceded by an Executive Summary. The text of the Report is organized into seven sections as follows:

Section 1 discusses the purpose, scope, organization of, and participants in this Report.

Section 2 classifies the 34 existing CSO outfalls as primary, relief or minor and describes their characteristic along with the following pertinent existing sewer system components: (1) regional treatment, (2) interceptor system, (3) collection system, (4) regulation, (5) relief system, (6) in-line storage modules, and (7) flood control. Outfall waterways are also discussed.

Section 3 discusses the investigative approach and the technical basis of the design approach for the proposed work.

Section 4 develops the alternatives for solids interception at the primary CSO outfalls. After preliminary evaluation to reduce the number of alternatives, the most advantageous first flush facility alternatives (1) swirl separation and (2) self-cleaning, rotating drum screens, and their auxiliary facilities were compared based on effectiveness, long-term environmental, and fiscal criteria. Options for relief and minor outfalls are also evaluated.

Section 5 presents the design criteria and data for the proposed facilities at the three types of outfalls along with the required auxiliary construction. Also discussed are: (1) the proposed operating and maintenance cycles, and (2) environmental impacts during construction and proposed mitigation.

Section 6 discusses costs, funding, permits, and schedule. Costs defined include: (1) construction, (2) project, (3) annual operating, (4) present worth, (5) annual total, and (6) annual per household.

Section 7 presents a narrative of the proposed work at each outfall including sizes, capacities, facilities and environmental concerns at the specific sites.

1.4 Participants

The main participants involved in the preparation of this Report and the implementation of its recommendations are: (1) the City of Elizabeth (City), (2) the Essex-Union Joint Meeting (EUJM), (3) the New Jersey Department of Environmental Protection and Energy (NJDEPE), (4) Clinton Bogert Associates (CBA), and (5) CBA subcontractors.

1.4.1 City of Elizabeth. The City, New Jersey's fourth most populous with 110,000 residents, is the Union County Seat. The 11.7 square mile City is located along the west banks of tidal Newark Bay and Arthur Kill. First settled in the 1660s, the City's urban development was accelerated in the nineteenth and early twentieth century by its location along interstate roads, rail-lines, and marine waterways.

In the 1990s, the City is mature, with little vacant land and a stable population. Land use in the City's low lying eastern section is nearly all industrial. Port Elizabeth and Newark Airport are located immediately northeast of the developed urban area. The City's central and western sections, separated by the Elizabeth River, include a mix of urban residences, commerce, institutions and light industry.

1.4.2 Essex-Union Joint Meeting. The EUJM owns and operates the regional trunk sewer system and treatment plant that serves the City. Restrictions on the volume of flow that may be intercepted were discussed with EUJM Executive Director Michael Brinker.

1.4.3 New Jersey Department of Environmental Protection and Energy. The Consent Agreement between the City and the Enforcement branch of the NJDEPE resulted in the construction of Contract 21 facilities that abated dry weather overflows and Contract 17 facilities that intercepted first flush and prevented the buildup of solids deposits. The scope of this Report was in conformance with NJDEPE requirements, and was pre-approved by them. The recommendations of this Report must conform to NJDEPE policy, and require NJDEPE approval. Upon approval and an additional appropriation by the State, the NJDEPE could authorize a 90 percent grant to prepare contract documents for the construction of the recommended facilities.

1.4.4 Clinton Bogert Associates. CBA Consulting Engineers with input from their Subcontractors prepared this Report and the engineering analyses and evaluations therein. CBA has provided engineering reports and contract documents for the City's CSO abatement program since its inception. Several of these innovative projects have won engineering excellence awards. Design concepts developed By CBA for the City were published as a 1978 USEPA Research and Development Manual, and appear in the WPCF 1989 Manual of Practice for CSO Pollution Abatement.

1.4.5 CBA Subcontractors. Subcontractors to CBA for this Report include: (1) Historic Sites Research, who prepared the Stage IA Cultural Resource Survey included under separate cover as Appendix; and (2) A-Tech, who field inspected and video-taped each CSO outfall and regulator, and provided written and oral narratives.

SECTION 2
EXISTING SEWERAGE SYSTEM

SECTION 2

EXISTING SEWERAGE SYSTEM

The City is served by a partially separated combined sewer system. The 17 primary combined outfalls discharge combined flows from about 4.2 square miles, mixed with sanitary flow from an additional 1.0 square mile. The nine relief outfalls discharge a portion of the higher combined flows diverted from about 2.0 square miles of the primary outfall service area. The eight minor outfalls discharge combined flows from about 0.1 square mile.

Not all systems discharge excess flows to waterways. Combined and separate surface drainage from about 0.2 square mile flows directly into the Westerly Interceptor. Combined drainage from about 0.3 square mile flows directly into the EUJM Trunks. A separate sanitary system serves an eastern portion of the City that includes Port Elizabeth and the industrial area in the former tidal marshlands and discharges directly to the Easterly Interceptor.

Section 2.1 discusses the various portions of the existing sewerage system that are pertinent to the City's CSO outfall system. Section 2.2 discusses the specific characteristics of the 34 permitted outfalls. Section 2.3 describes the waterway to which the outfalls discharge.

2.1 Pertinent System Components

Pertinent aspects of the sewerage system discussed herein include: (1) treatment, (2) interceptors, (3) collection system, (4) intercepted flow regulation, (5) relief sewers, (6) CSO pollution control modules, and (7) Elizabeth River flood control improvements.

2.1.1 Sewage Treatment. All sanitary sewage, and limited rates of combined sewage, from Elizabeth are conveyed by intercepting sewers and a pumping station to the regional Essex/Union Joint Meeting (EUJM) Treatment Plant in southeastern Elizabeth. Plant effluent is provided secondary treatment and discharges to the Arthur Kill. In 1992, flows from Elizabeth constituted about 25 percent of the average 66 mgd EUJM Plant flow. The other 16 municipalities tributary to the EUJM upstream are reported to have separate sanitary systems.

2.1.2 Interceptor Systems. Both the EUJM and the City have sewer system that intercept the City's flows. All of the 34 permitted CSO outfalls are associated with the City's interceptor system.

EUJM. The Joint Meeting of Essex and Union Counties (EUJM) receives sewage, from about 440,000 residents in northeastern Union and southwestern Essex Counties in the Elizabeth and Rahway River watersheds. Parallel EUJM trunk sewers, the Original and the larger Supplementary trunk, convey upstream flow and extend about four miles through Elizabeth, between the treatment plant and the Union Township boundary, along the City's southwestern boundary. About 8.5 percent of Elizabeth's sewage, from the partially combined Elmora section, enters the EUJM Trunks by gravity. By Contract agreement, the peak rate of flow that the directly connected Elmora section may discharge to the EUJM plant is 4 mgd.

City. The remaining 91.5 percent of the City's flow is pumped by the City's Trenton Avenue Pumping Station (TAPS) on the east bank of the Elizabeth River, to the EUJM trunk sewer 0.2 mile upstream of treatment plant. By Contract agreement the peak rate of flow that TAPS may discharge to EUJM is 36 mgd. Two municipal gravity interceptors, the Westerly and Easterly, convey the City's sewage to TAPS. Plates 5.1.1 and 5.1.2 show the routes of these interceptors.

Westerly Interceptor. The City's 2.2-mile Westerly Interceptor extends northwesterly through the City near the east side of the Elizabeth River to Bridge Street, where it crosses to the west side of the river. Its upstream end is at Westfield Avenue. The 0.5-mile section south of Summer Street is 60- and 48-inch concrete sewer constructed in 1958, with capacity for twice the dry weather peak flow. The 40-through-28-inch brick section of the Westerly Interceptor between Summer Street and Westfield Avenue, constructed in 1912, has limited capacity to convey combined sewage flows in excess of the maximum dry weather flow (DWF) rates. This upper section of the Westerly Interceptor was lined with a low friction Insituform lining in 1986, to provide capacity to convey the maximum DWF rate.

Easterly Interceptor. The 60-to-33-inch, 4.0-mile, concrete, Easterly Interceptor was constructed in 1958, to provide treatment to City flows which formerly discharged to Arthur Kill, Newark Bay and the eastern ditches. From TAPS, its route extends: (1) southeasterly along the tidal Elizabeth River, (2) northeasterly along South First Street to Elizabeth Avenue, (3) northeasterly along Front Street to Ripley Place, (4) northwesterly generally parallel to Conrail to the NJ Turnpike, (5) northerly along Dowd Avenue to Route 1. The Easterly Interceptor has capacity to convey about three times the maximum DWF rate.

2.1.3 Collection System. There are presently about 120 miles of intercepted sewers in Elizabeth's collection system, excluding building connections. In the nineteenth and early twentieth century, the City

This is 0.65 percent of the median annual 1993 household income of $31,000 as determined by U.S. Census data adjusted by the CPI.

9b. Affordability. Based on conversations with NJDEPE, the criteria for acceptable user charge burden is based on the criteria for ineligibility for Level 1 environmental review in "Grants for Wastewater Facilities" 7:22-10.4 (b) 3. This criteria is that if the user cost for the project significantly exceeds 1.75 percent of the median annual household income, it is not affordable. The total annual sewer user charge would be 0.65 percent, which by definition is an affordable user charge.

10. Identify owner operator

10. Owner/Operator. The City of Elizabeth, N.J., is the owner and operator of the City sewer system, and would own and operate the components of the proposed Project.

11A. Provide area to be disturbed in acres

11A. Disturbed Area. Table 11 in Attachment 11 lists the acreage to be disturbed by the proposed work to eliminate the discharge of solids/floatables at each outfall. The Table subdivides the area disturbed by FFF and DASF construction and by non contiguous piping. The areas to be disturbed to construct each of the 13 FFF and contiguous DASF and other chambers is less than 0.3 acre.

11B. Specific impacts to wetland, steep slopes, vegetation and Green Acres

11B. a. Wetlands. The impact of the project on wetlands is discussed in the response to Comment 1Ab.

11B. b. Steep Slopes. There are no steep slopes that will be impacted by the project.

11B. c. Vegetation. The impact of the project on vegetation is discussed in the response to Comment 1Ag.

11B. d. Green Acres. The impact of the project on Green Acres is discussed in the response to comment 1Ac.

12. Resource Inventory Deficiencies
a. existing water quality

12a. Existing Waterway Quality. A discussion of the existing water quality is included in the response to Comment 4.

b. existing facilities
1. service area condition

12b. 1. Service Area. The existing Service Area condition was briefly described in Report Section 1.4.1. A more comprehensive description follows:

Geographic Location. The 11.7 square mile City is located along the west banks of tidal Newark Bay and Arthur Kill between Latitudes 40 degrees 38-to-42 minutes North and Longitudes 74 degrees 09-to-15 minutes West. Elizabeth is bounded by Newark on the northeast, Union and Hillside on the northwest, Linden, Roselle and Roselle Park on the southwest, and Arthur Kill on the southeast. The Elizabeth River traverses the City from north to south. U.S. Route 1, the New Jersey Turnpike Exits 13 and 13A, and Route I-278 at the Goethals Bridge terminus are part of the City's interstate road system. The Amtrak Northeast Corridor and Conrail Elizabeth Industrial Track intersect at the City's commercial Center. Newark International Airport and the Port of Elizabeth occupy much of northeastern Elizabeth.

Development. Urban development was accelerated in the late nineteenth and early twentieth century, aided by the City's location along interstate roads, rail-lines, marine waterways and its location within the greater New York-New Jersey Metropolitan Region. Most of the City's subsurface water, gas and sewer infrastructure was constructed during this period. By 1930, the City's population was 115,000 — 5,000 more than its present population of 110,000. Since 1930, most new housing stock has been multifamily.

Since the 1960s, the Port of Elizabeth, part of the nation's largest container port, the extension of Newark International Airport and associated industries were constructed in northeastern Elizabeth. Many of the nineteenth century manufacturing industrial buildings were either razed to make way for more modern industries, or have been converted to warehouse operations. Between 1969 and 1986, employment in Elizabeth decreased from about 51,000 to 43,000. During that period, trade and office employment increased by 3,000 while manufacturing employment decreased by 11,000. In the 1990s, the City is mature, with little vacant land and a stable population.

Land Use. The City's low-lying eastern section is occupied by Port Elizabeth and Newark Airport and other industrial development, much relating to port activities. The City's central and western sections, separated by the Elizabeth River, include a mix of urban residences, commerce, institutions and light industry. Most residences are in multi-family housing. Only about 7,400 of the City's 41,000 dwelling units are single family, most of which are in the City's northwestern quadrant. The central business district, which also contains the City and County Administrative buildings, is located south of the Amtrak-Conrail crossing along the east side of the Elizabeth River.

Drainage and Waterways. The City has three drainage areas, (a) the southern area that drains to Arthur Kill and Newark Bay, (b) the central and western area that drains to the Elizabeth River and (c) the eastern area that drains to the Great Ditch and the Newark Airport Peripheral Ditch. Newark Bay and Arthur Kill are navigable, tidal marine waterways. The Elizabeth River, which has a drainage area of 23 square miles and flows southward 4 miles through the City, is tidal south of Rahway Avenue and is channelled in a concrete flume north of U.S. Route 1 and by earthen embankments to the south. Tide gates at the outlets of the Great and the Peripheral Ditches, which drain about 10 square miles, prevent saltwater intrusion into these waterways. Surface drainage patterns have been modified by storm and combined sewers that cross low ridge lines.

Topography. The industrial area, seaport and airport in northeastern Elizabeth are very flat and generally below Elevation 12. Most of this land is filled reclaimed tidal marsh. Ground slopes in the rest of the City are generally around one to three percent, and the terrain is slightly rolling. The surface slopes to the waterways are uneven, and in some locations reversed, creating local sumps that lack constructed combined sewers to discharge the storm runoff and sanitary wastes from developed areas to the nearest water courses. These were: (1) the Elizabeth River for the central and western portions of the City and (2) the Arthur Kill, Newark Bay and Great Ditch for the eastern portion. With the advent of treatment and subsequent construction interceptors, (1) a regulated rate of sewage was diverted into the interceptors at the locations where each combined sewer outfall passed over the interceptor, and (2) separate storm and sanitary sewers were constructed to serve newly developed areas.

2.1.4 Regulated Combined Sewage Interception

Need for Limitation. The average dry weather sanitary flow rate is equal to about 0.01 in/hr of rainfall runoff. Combined sewage flows, therefore, substantially exceed the sanitary flow quantities during moderate rainfall. The City's larger combined sewers have several times the capacity of its interceptors. At each point of combined sewage interception, it is necessary to limit the rate of flow entering the interceptor. If not limited by the hydraulic capacity of the interconnection, the rate is limited by the capacity of the interceptor or of TAPS, which is currently limited to 36 mgd.

Excess Flow Path. Excess combined sewage overflows a DWF diversion dam and discharges to the waterway via the outfall. Where the DWF diversion dam crest is below the tidal or river level, tide gates are provided on the outfall to prevent the interception of waterway flow. At several outfalls, the initial volume of excess flow is stored in-pipe by a storage module, as described in Section 2.1.6.

Present Regulation. Originally most points of combined sewage interception were equipped with float operated regulator gates that limited the flow into the interceptor. Due to obsolescence, many of the float operated gates have been abandoned or removed. The rates of interception are now controlled by fixed orifices, vortex valves and knife gates.

Fixed Orifice. Fixed orifice regulation permits the intercepted flow to vary in proportion to the square root of the difference in the hydraulic gradient elevations of the interceptor and the collection system sewer at the point of interception. Twice the flow will be intercepted with a hydraulic gradient difference of 4.0 feet than with a difference of 1.0 foot. Because of this wide range, fixed orifice regulation is not effective where control of flow rate to the interceptor is required.

Vortex Valve. Vortex valves provide a relatively constant discharge, using an internal spiral flow pattern to dissipate the energy generated by high hydraulic gradient elevations. Under low hydraulic gradient conditions, the vortex valve functions as an orifice with a flow-proportional orifice coefficient of 0.6. Under high hydraulic gradient conditions, the vortex pattern reduces the orifice coefficient to as low as 0.15 depending on the geometry of the valve.

Knife Gates. To further regulate and optimize combined sewage interception, the City installed structures on Primary Outfall 005 and relief Outfalls 036 and 042 to store combined sewage to the extent practical to permit regulated delivery to the EUJM for treatment. The connection to the interceptor from these structures includes a normally open knife gate to divert DWF and the stored combined sewage at a controlled rate to the interceptor. When the storage is filled a flap gate opens to discharge stored combined sewage to the Elizabeth River to prevent interior flooding, and the knife gates shut, ceasing interception.

2.1.5 Combined System Relief. Most of the original combined sewers had insufficient capacity to prevent frequent upstream flooding. Accordingly, the City installed several relief and separate storm sewers. Relief sewers have one or more upstream interconnections that permit surcharged combined sewers to overflow into the relief sewers. Separate storm sewers have no combined system interconnections. By intercepting drain inlets along their route that had been tributary to combined sewers, both relief and separate storm sewers reduced the drainage area tributary to the combined sewers.

2.1.6 Pollution Abatement Program. In the 1980's, the City implemented phases of the program developed in the 1981 Facilities Plan "CSO Pollution Abatement Program". Pertinent elements of the program that were implemented included: (1) increasing the capacity of the Westerly Interceptor, (2) constructing 13 in-line storage modules on sewers with substantial in-line storage capacity. (3) providing regulated interception of first flush flows from the sewers equipped with storage modules, and (4) installing 11 combined sewer flushing modules, that daily re-suspend solids settled in the inverts to prevent their resuspension and discharge to the waterway during wet weather.

2.1.7 River Flooding Abatement. During the late 1970's and early 1980's, the US Corps of Engineers (COE) implemented a major program to abate Elizabeth River flooding by increasing the flow capacity of the River. All of the City's CSO outfalls to the Elizabeth River and most of the crossing bridges were reconstructed. Some outfalls were equipped with gates. Surface ponding areas were provided with pumping facilities to drain the ponds when high river water elevation prevents gravity drainage.

2.2 Outfalls with CSO Permits

Elizabeth's 34, permitted outfalls have been classified herein as follows: (1) 17 as primary, (2) 9 as relief, and (3) 8 as minor. Primary outfalls serve significant drainage areas, and overflow when the capacity of the regulated interception connection is exceeded. Relief outfalls discharge CSO only when the upstream flow levels in adjacent combined sewers rises to the level of interconnections between the combined and relief system. Minor outfalls serve relatively small drainage areas, or partially separated drainage areas, and discharge when the capacity of the regulated interception connection is exceeded.

2.2.1 Primary Outfalls. Table 2.2.1 lists the 17 primary outfalls along with their: (1) discharge waterway (2) outfall sizes, (3) tributary drainage areas, subdivided by combined sewer areas and connected sanitary sewer areas, and (4) upstream storage module capacities, and (5) flushing modules presently in operation.

TABLE 2.2.1

PRIMARY CSO OUTFALLS

			Areas Served (acres)		Modules	
Outfall Number	**Street-Waterway-Bank***	**Diam (in.)**	**Combined**	**Connected Sanitary**	**Flushing**	**Storage Capacity (mg)**
(along Easterly Interceptor north to south)						
001	Alina-Peripheral Ditch	48	289	119	3	0.30
002	Dowd-Great Ditch	48	166	126		
034	Puleo-Newark Bay	50	365	85	1	
032	Magnolia-Arthur Kill	36 x 54	56			
031	Livingston-Arthur Kill	36	68			
029	Elizabeth-Elizabeth River-E	48	95			
035	Third-Elizabeth River-E	60	133		1	0.17
~~012~~	Bayway-Arthur Kill	72	95			
(along Westerly Interceptor north to south)						
005	Harrison-Elizabeth River-E	84	829	300	3	0.34
006	Crane-Elizabeth River-E	21	13	7		
010	Murray-Elizabeth River-W	48	57			
011	Rahway-Elizabeth River-W	24	39			
013	Burnett-Elizabeth River-W	24	34			
022	South-Elizabeth River-E	48 x 72	181	3	3	
026	John-Elizabeth River-E	48	117		1	
028	Summer-Elizabeth River-W	66	240	40	1	0.35
040	Clifton-Elizabeth River-W	54	59	13		

*E and W signify east and west bank of the Elizabeth River.

2.2.2 Relief Sewer Outfalls. Table 2.2.2 lists the nine relief sewers along with: (1) the combined outfall system relieved, (2) relief outfall sizes, (3) tributary separate storm areas, (4) capacity of storage modules and (5) method of interception. These relief sewers primarily discharge separate storm runoff, and discharge combined sewage only during higher intensity rainfall.

TABLE 2.2.2

RELIEF OUTFALLS

Outfall Number	Name Street and Bank*	Relieved Outfall System Number	Outfall Diam (in.)	Tributary Separate Drainage Area	Storage Module Capacity (mg)	Interception to Treatment
Great Ditch						
039	Schiller	034	36	85		None
Arthur Kill						
030	Jersey	029	48	NA		None
Elizabeth River north to south						
036	Dowd-E	005	106 x 166	140	1.81	Vortex to 005
041	Morris-W	005	66	NA	0.39	Siphon to 005
003	Westfield-W	041/005	90	85	0.59	To be pumped
042	Bridge-E	042	113 x 72	110	0.34	Vortex to Westerly
021	Spring-E	022	24	3		None
028	Summer-W	027	60	NA	**	Vortex to Westerly
038	Atlantic-E	035	48	26		None

*E and W signify east and west bank of the Elizabeth River.
**Shares 0.35 mg with primary Outfall 027.

2.2.3 Minor Outfalls. Table 2.2.3 lists the eight minor outfalls to the Elizabeth River that are intercepted by the Westerly Interceptor, along with their diameters and partially separated service areas. These minor outfalls serve small combined areas, which may have been partially separated, and which may more readily be fully separated than outlet-controlled.

TABLE 2.2.3

MINOR CSO OUTFALLS
Elizabeth River north to south

Outfall Number	Name Street-Bank	Diam (in.)	Service Area (acres)
007	Grand-E	15	8
008	Grand-W	15	14
009	Caldwell-E	15	10
012	Rahway-E	18	18**
014	Broad-E	18	9**
016	Broad-W	24 x 36	60**
024	Norwood-W	15	7
025	Montgomery-W	15	4

*E and W signify east and west bank of the Elizabeth River.
**Portions of these areas have been separated.

2.3 Waterways

The 34 CSO outfalls discharges to five waterways: (1) 26 to the Elizabeth River, (2) four to Arthur Kill (3) one to Newark Bay (4) two to the Great Ditch and (5) one to the Peripheral Ditch.

2.3.1 Waterway Classification. The NJDEPE classifies these waterways based on their best use. The discharge waterway have three different designations: (1) FW2-NT, (2) SE2 and (3) SE3. The designation SE indicates a saline estuary. FW indicates fresh water with salinity less than 3.5 parts per thousand at high tide. NT indicates not suitable for trout maintenance. The "3" designation is indicative of the lowest use expectation. The "2" designation is indicative of higher use expectation.

FW-2 Usage. Typical usage of FW2 waterways includes: (1) maintenance, migration and propagation of the natural and established biota, (2) primary and secondary contact recreation, (3) industrial and agricultural water supply, (4) public and potable water supply after such treatment as required by law or regulation, and (5) any other reasonable uses.

SE-2 Usage. Typical usage of SE2 waterways includes: (1) maintenance, migration and propagation of the natural and established biota, (2) migration of diadromous fish, (3) maintenance of wild life, (4) secondary contact recreation, and (5) any other reasonable uses.

SE-3 Usage. Typical usage of SE3 waterways includes: (1) maintenance, migration of fish populations, (2) migration of diadromous fish, (3) maintenance of wild life, (4) secondary contact recreation, and (5) any other reasonable uses.

2.3.2 Elizabeth River. The Elizabeth River drains about 23 square miles in eastern Union and southern Essex Counties. It extends four miles through the City, from its outlet to Arthur Kill to Ursino Dam at the Hillside-Union boundary.

Downstream Segment. The downstream two mile river segment from Arthur Kill to the Route 1 crossing is a trapezoidal earthen channel. The flow direction oscillates in response to the tide. Five primary CSO and three relief outfalls discharge to this section The NJDEPE classifies this section as SE3,

Upstream Segment. Flow in the upstream two-mile river segment, from Route 1 to Ursino Dam, is contained in a 40 foot wide concrete flume that winds through the City's commercial center. Flow is tidally influenced, heavily at Route 1 but not at Ursino Dam. Six primary outfalls, four relief outfalls, and all eight minor CSO Outfalls discharge to this segment. The NJDEPE classifies this section as SE3 downstream of the Broad Street bridge and FW2-NT upstream.

2.3.3 Arthur Kill. The 15-mile Arthur Kill is a tidal marine waterway, that connects Newark Bay and Raritan Bay, and forms the New York/New Jersey boundary. A 400-to-600 foot wide shipping channel is maintained in the 500-to-1000-foot wide Kill. Flow direction alternates in response to the tide. Primary Outfalls 031, 032 and 037 and relief Outfall 030 discharge to the Kill. The NJDEPE classifies the section of the Kill that bounds the City as SE3.

2.3.4 Newark Bay. The five-mile long, 3000-to-6000 foot wide, tidal Newark Bay provides the outlet to the Hackensack and Passaic River. Two of the nations largest shipping ports, Port Elizabeth and Part Newark line the western bank. Flow direction alternates in response to the tide. Primary Outfalls 034, as well as CSO outfalls in Bayonne and Jersey City discharge into the Bay. The NJDEPE classifies the Bay as SE3.

2.3.5 Great Ditch. The Great Ditch drains about one square mile of eastern Elizabeth, between Conrail and North Avenue, to Newark Bay. Tide gates prevent an alternating flow pattern. Primary

Outfall 002 and relief Outfall 039 discharge to this tidal ditch. The NJDEPE classifies miscellaneous ditches tributary to Newark Bay that have salinity less than 3.5 parts per thousand, as FW2-NT.

2.3.6 Newark Airport Peripheral Ditch. This tidal, serpentine, waterway, constructed in the 1960's as a part of the expansion of Newark Airport drains about ten square miles of northeastern Elizabeth and southern Newark. Tide gates prevent an alternating flow pattern. Primary Outfall 001 and five primary CSO outfalls from southern Newark are the major source of flow into the waterway. The NJDEPE classifies miscellaneous ditches tributary to Newark Bay that have salinity less than 3.5 parts per thousand, as FW2-NT.

SECTION 3
APPROACH

SECTION 3

APPROACH

The facilities developed in this Report are derived from the investigative and analytical procedures presented in Section 3.1, and the technical basis of proposed work, presented in Section 3.2

3.1 Investigative and Analytical Procedures

The investigative and analytical steps included: (1) report and sewer map review, (2) pertinent contract drawing review, (3) initial system analysis, (4) field investigations, (5) tributary flow analysis, (6) historical rainfall analysis, (7) CSO loading analysis, (8) interception analysis, (9) in-line storage analysis, (10) tidal analysis, (11) equipment investigations, and (12) site selections.

3.1.1 Report and Map Review. Initially, the Reports and maps defining Elizabeth's combined sewer system were reviewed. A description of some of the more pertinent documents follows.

Fuertes Sewer Maps. The 43 drawings defining the City's sewer system were first created in 1921 as part of a sewer improvement plan, and last updated in 1980. These maps present all City sewers, sewer sizes, catch basins and manholes and regulators on a 1-inch equal 100-foot scale. Selected invert, rim and street elevations are also provided.

Report on Sewerage Drainage and Flood Control Improvement Program. The 1962 Report, provided a master plan for abating the serious internal flooding resulting from limited combined sewer capacities, limited Elizabeth River capacity, and low sump elevations. The prime recommendation was a plan to separate Elizabeth's combined system by constructing large separate storm drains capable of conveying a five-year storm flow. Many recommendations were implemented during the 1960's, including the District E and H Storm Drains. Due to escalating costs and lack of Federal assistance, the separation program was not implemented after the early 1970's.

Phase 1-Infiltration/Inflow Studies. This 1974 Report indicated the points of CSO overflow and the tributary areas. The Report raised the need for determining whether an advanced combined system in Elizabeth might be more cost-effective than the separation proposed in the 1962 Master Plan.

Conventional and Advanced Sewer Design Concepts for Dual Purpose Flood and Pollution Control - A Preliminary Case Study - Elizabeth, N.J. This 1978 USEPA Research and Development Report was based on model of the City's sewer system and its rainfall pattern. The Report concluded that capturing the first flush was essential for pollution control, and that an advanced combined system would discharge less pollutants that a separate system.

Combined Sewer Overflow Pollution Abatement Program. This 1981 Facilities Plan developed a plan to abate much of the CSO pollutants by maximum use of existing facilities to reduce the costs. Proposed elements included modules to provide in-pipe storage for combined sewage with later diversion to treatment, flushing modules to limit the deposit of sewage solids in large, flat combined sewers during dry weather, and increased interceptor capacity. The initial phases of the program were implemented in the mid and late 1980s as Contracts 17 and 21. The need for implementing further, less cost-effective phases, which include off-line storage, were to be determined by an analysis of the river water quality now in progress.

Comprehensive Master Plan. This 1990 Report updated the City's land use plans and zoning.

Elizabeth Flows to Joint Meeting Facilities. This 1992 Interim I/I Study Report updated the flow figures in previous reports and indicated the interconnections between the portions of the Elizabeth combined system tributary to the EUJM trunk sewers and to the TAPS.

3.1.2 Contract Drawing Review. As a second initial investigative step the contract documents defining improvements to and relief for Elizabeth's combined sewer system were reviewed. A description of some of the more pertinent documents follows:

West End Relief Sewer. This 1939 constructed relief sewer diverted flows in western Elizabeth and tributary to Outfall 005 and the EUJM trunks to Relief Outfall 003.

Easterly Interceptor and Regulators. This 1958 project ended the discharge of dry weather raw sewage from southern and eastern Elizabeth to the Great Ditch, the lower end of the Elizabeth River, and most of the dry weather discharge to Newark Bay and Arthur Kill.

Northwesterly Drainage Relief. This 1960 storm sewer project substantially reduced the combined area tributary to Outfall 001.

District H Storm Drainage Contracts 1, 3 and 4. This 1963 relief sewer and storm drainage project provided adequate internal drainage for the city hall area including the Broad Street Amtrak underpass. Relief Outfall 042 was constructed at this time, replacing several combined outfalls.

Bayway and East Side Industrial Sewer-Contract 2. This 1967 regulator and interceptor project ended the discharge of dry weather raw sewage from Southern Elizabeth to Newark Bay from Outfall 034, and to Arthur Kill from Outfall 037.

District E Storm Drainage-Contract 5 and 6. This 1968 relief sewer and storm drainage project provided adequate internal drainage for the northern part of the City east of the Elizabeth River. It reduced significantly the drainage area tributary to Outfall 005. It further constricted the upstream combined flow to Outfall 005 with the construction of a limited capacity interceptor. Relief Outfall 036 was constructed at this time.

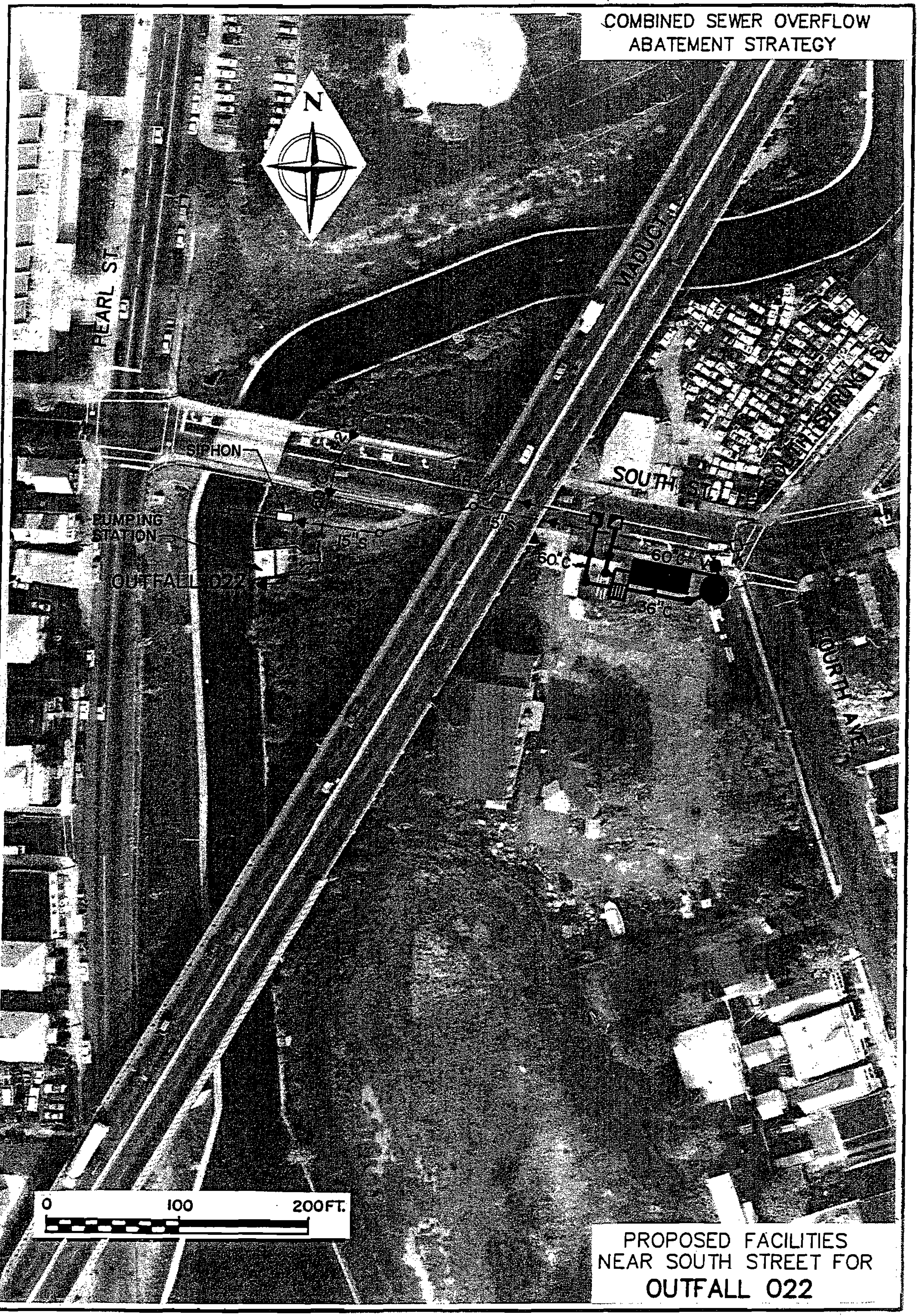
Elizabeth River Flood Control Project. This 1979-85 project by the US Corps of Engineer, as noted in Section 2.1.7, relieved flooding due to the previously limited hydraulic capacity of the river. Relief Outfall 041 at Morris Avenue was constructed at this time, with a downstream combined siphon that greatly restricted the flow to Outfall 005.

Division Street Storm Sewer. This 1980 storm sewer project constructed for the NJDOT eliminated flooding at the Division Street-Conrail underpass and reduced the drainage area tributary to Outfall 002.

Westerly Interceptor Sewer-Contract 17. This 1986 project was the initial phase of the CSO Abatement Plan and included the lining of the Westerly Interceptor to increase its hydraulic capacity sufficiently to handle the maximum DWF, and construction of storage module regulators at primary Outfalls 005 and 027/028

Flushing and Storage Modules-Contract 21. This 1988 project was the second part of the initial phase of the CSO Abatement Plan. The construction included: (1) 11 flushing modules to resuspend settled solids in flat sections of combined sewers tributary to primary Outfalls 001, 022, 026, 027, 029, 034, and 035, and (2) 11 in-line storage module regulators at primary Outfalls 001 and 035, relief Outfalls 003, 036, 041 and 042 and five storm sewer locations

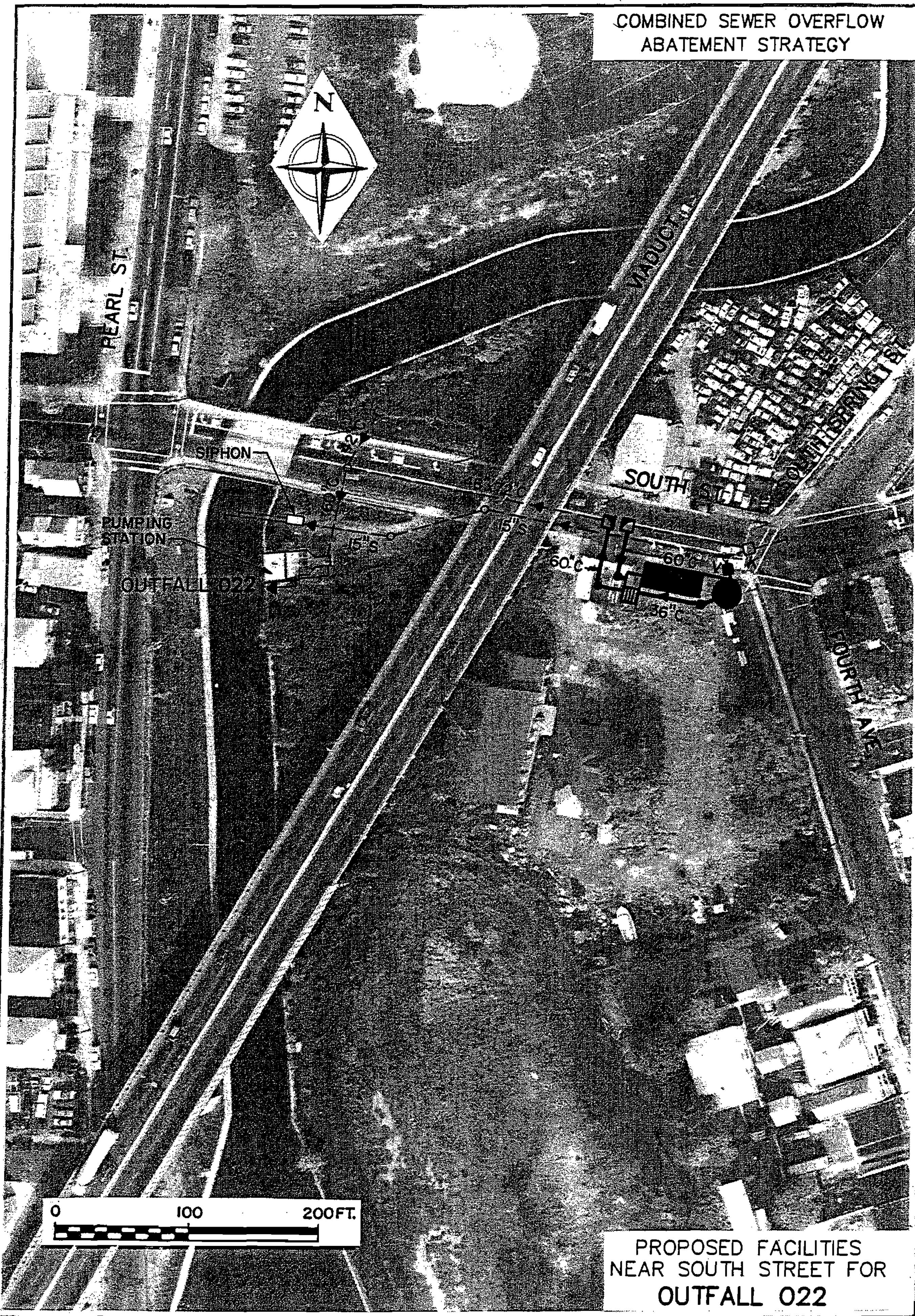
CITY OF ELIZABETH



PROPOSED FACILITIES
NEAR SOUTH STREET FOR
OUTFALL 022

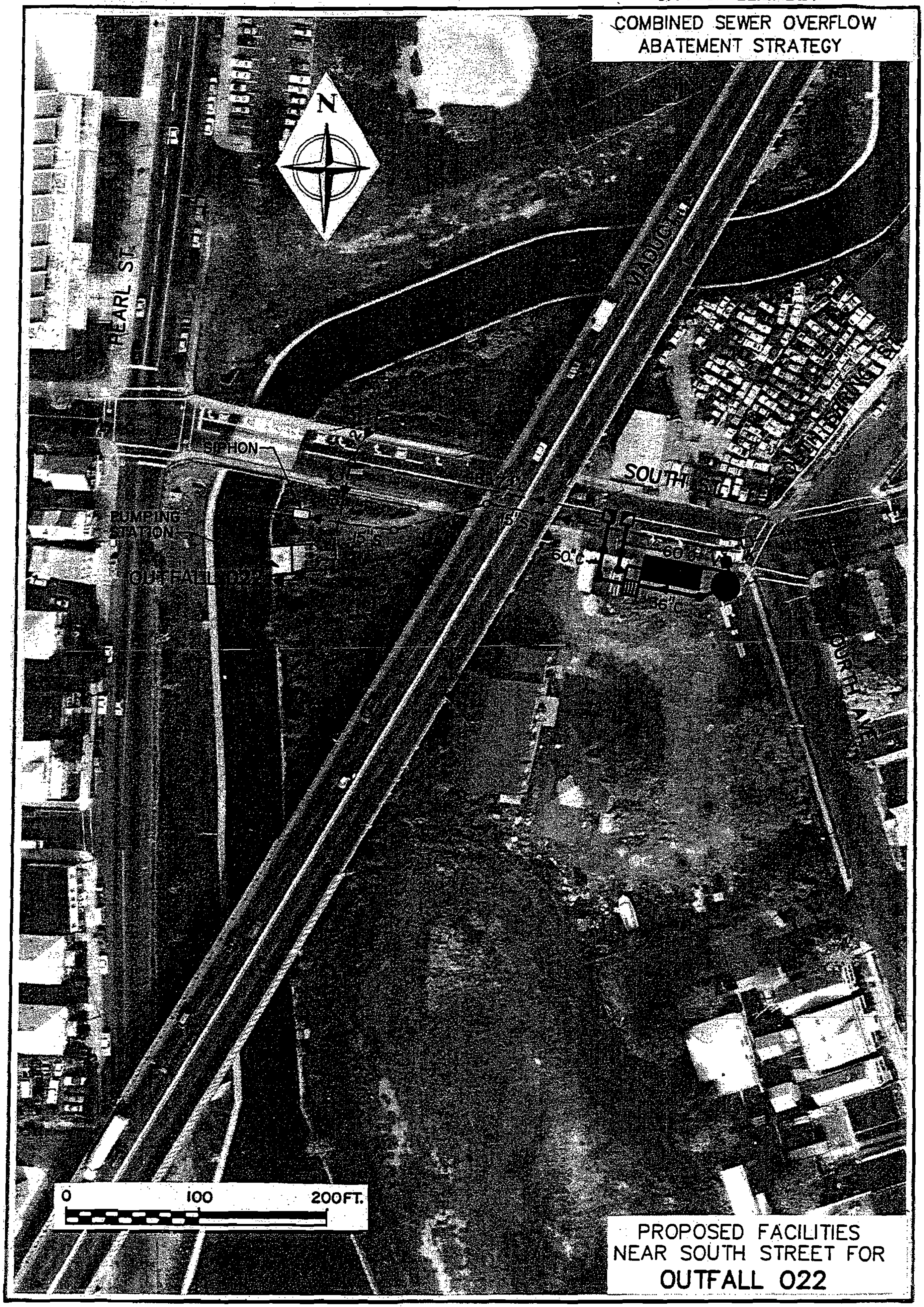
CLINTON BOGERT ASSOCIATES

CITY OF ELIZABETH



CLINTON BOGERT ASSOCIATES

CITY OF ELIZABETH



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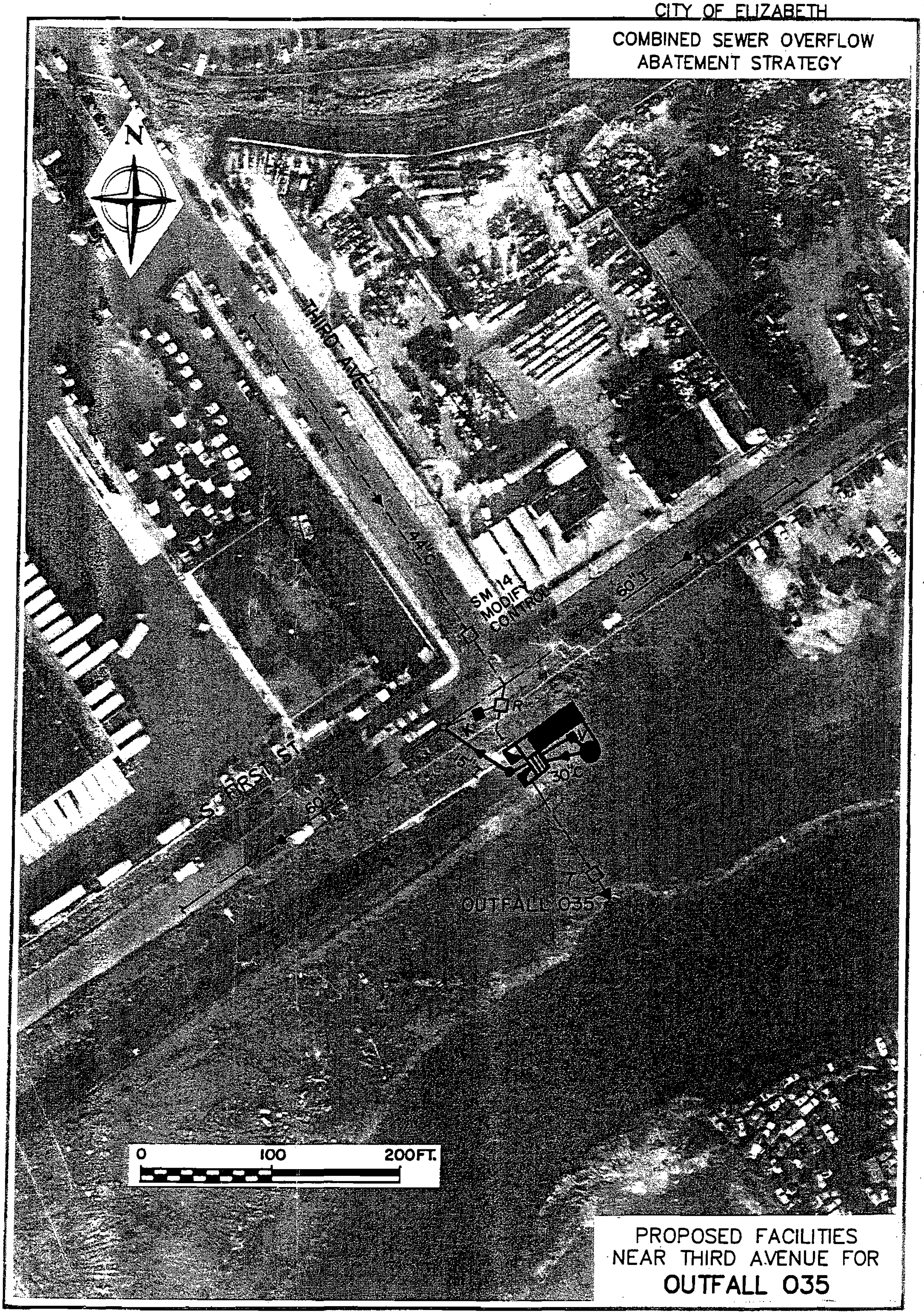
CITY OF ELIZABETH
COMBINED SEWER OVERFLOW
ABATEMENT STRATEGY
N
THIRD AVE
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OUTFALL 035
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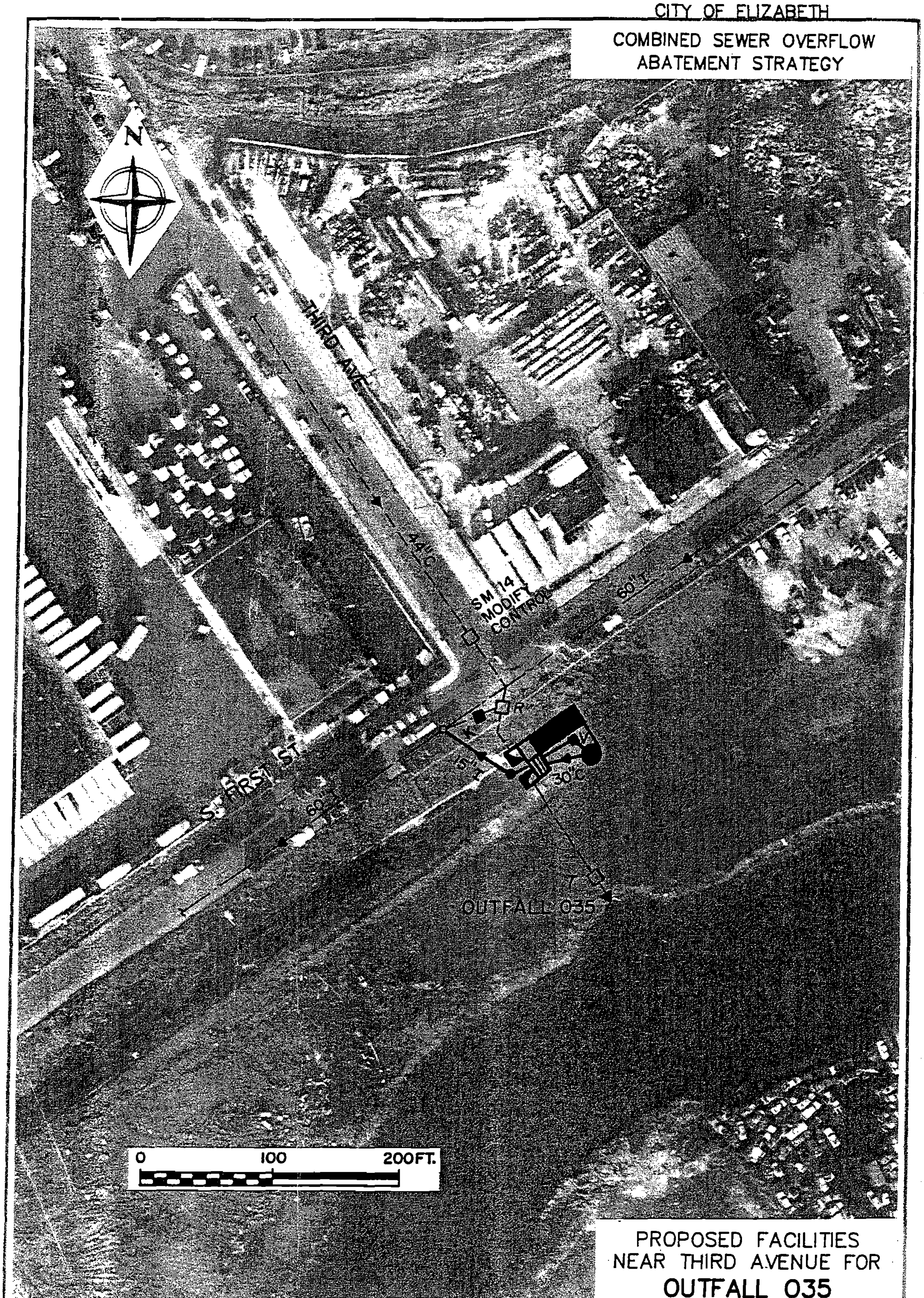
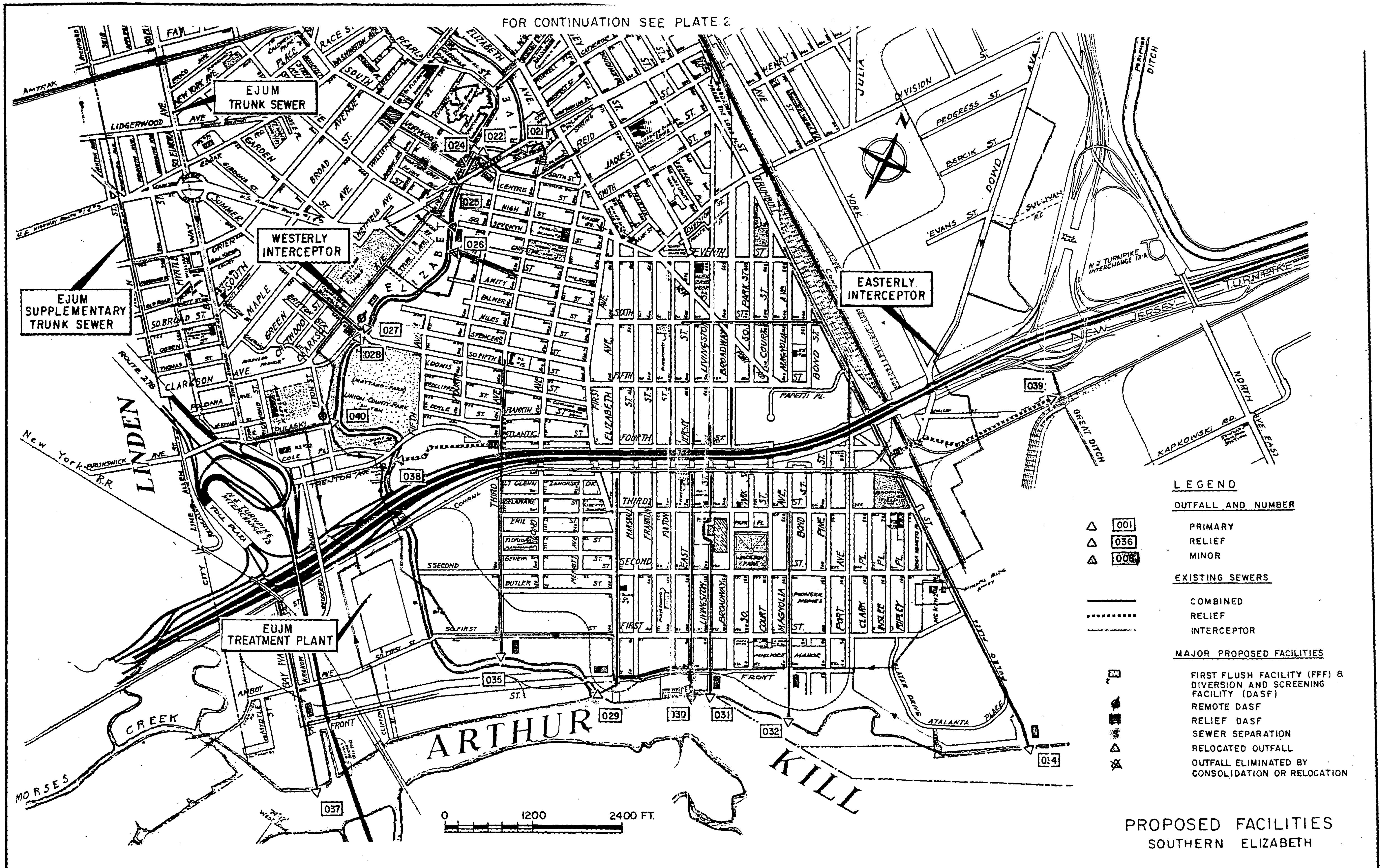
PROPOSED FACILITIES
NEAR THIRD AVENUE FOR
OUTFALL 035



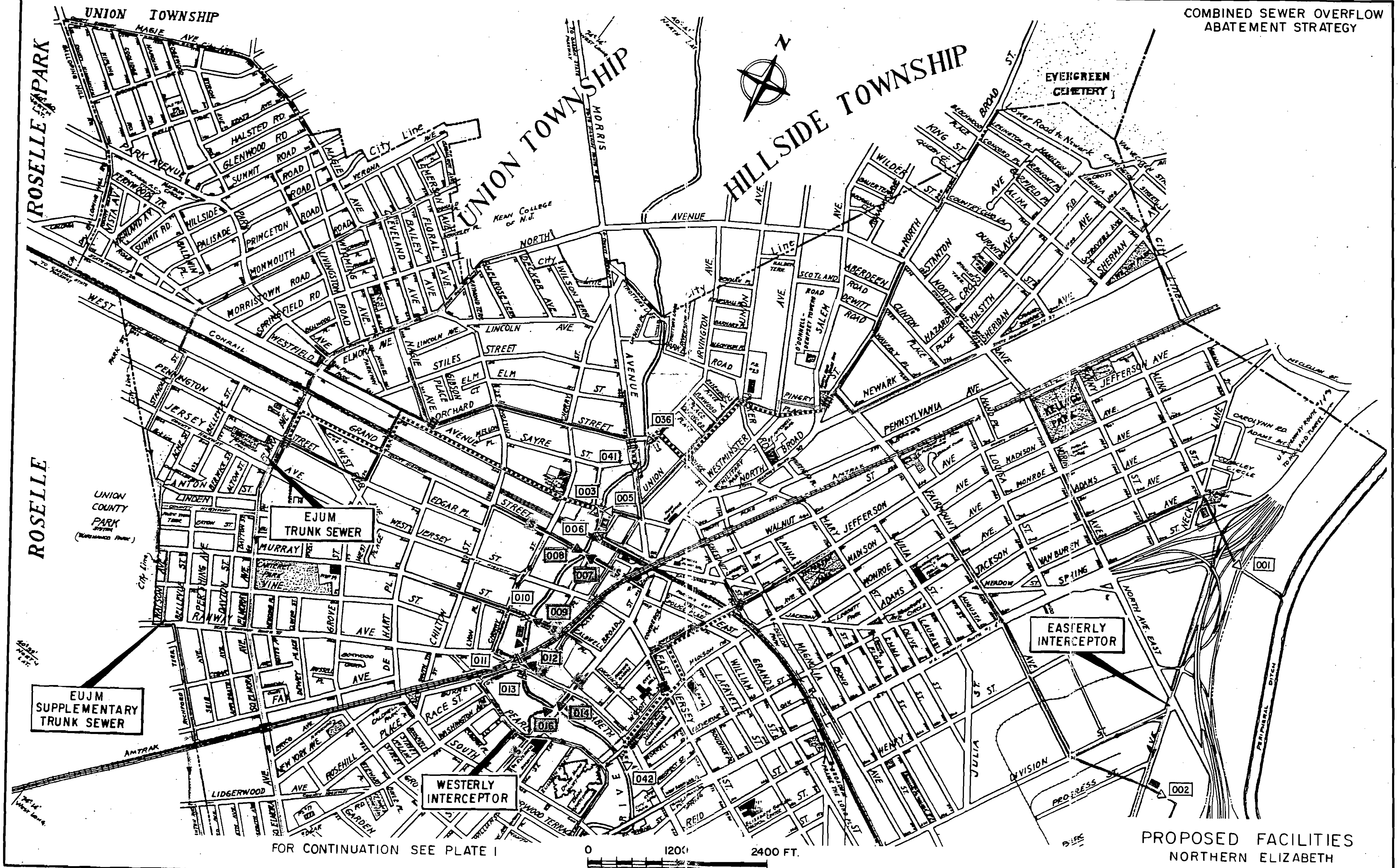
CLINTON BOGERT ASSOCIATES



PROPOSED FACILITIES
SOUTHERN ELIZABETH

CITY OF ELIZABETH

COMBINED SEWER OVERFLOW ABATEMENT STRATEGY



PROPOSED FACILITIES

NORTHERN ELIZABETH

CLINTON BOGERT ASSOCIATES

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Associates ▫ Consulting Engineers

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Mark A. Tompeck, P.E.
Senior Associate

January 25, 1999

Mr. Blaise Lapolla
Director of Public Works
City of Elizabeth
50 Winfield Scott Plaza
Elizabeth, New Jersey 07021

RECEIVED
State of New Jersey

FEB 11 1999

Dept. of Environmental Protection
Municipal Wastewater Assistance

**Re: 271003 - City of Elizabeth
Preliminary Design of Solids/Floatables
Control Facilities**

Dear Mr. Lapolla:

In accordance with the agreement between the City of Elizabeth and Killam Associates, we are pleased to present the following report which summarizes the findings of our analysis and serves as the basis for the final design of CSO solids/floatable control facilities for the City.

The report which follows includes sections which provide: a general background of the CSO system; a summary of the conditions of the facilities observed during inspections which were performed; the results hydrologic and hydraulic analysis performed; the analysis of alternatives for solids/floatables removal; and the basis for the final design of the facilities.

We thank you and members of the Department of Public Works and Engineering Department Staff for their valuable assistance during the preparation of this study and report. Following the review of the report by the City, we would be pleased to meet with you and your staff to discuss the findings and conclusions. Should you have any questions concerning the report, please do not hesitate to contact us.

Very truly yours,

KILLAM ASSOCIATES

Mark A. Tompeck

Mark A. Tompeck, P.E.

cc: N. DeNichilo
A. Bowyer

N:\ENG\271003\REPORT\LOT.WPD

City of Elizabeth
CSO Solids/Floatables Control Facilities
Preliminary Design Report

List of Appendices

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Page No.

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List of Plates (Continued)

List of Plates (Continued)

List of Plates (Continued)

The City of Elizabeth, located in the northeastern part of New Jersey in Union County, had a 1990 population of approximately 110,000. The City is a densely developed urban area consisting primarily of industrial development in the eastern portion and a mix of residential, commercial, institutional and light industrial development in the central and western portions.

The City of Elizabeth owns, and through its Department of Public Works, operates a combined sewer system, which, during dry weather, discharges wastewater to the Joint Meeting of Essex and Union Counties (JMEUC) wastewater treatment plant located in Elizabeth. Elizabeth's sewer system is sixty-eight percent combined (sanitary sewage and stormwater runoff in a common pipe) and is reported to be between 50 and 100 years old. The combined sewer system collects wastewater and stormwater from approximately 4,250 acres and presently contains 34 combined sewer overflows (CSOs). The CSOs are activated during storm events and discharge diluted raw sewage to the receiving water bodies surrounding the City.

The Sewage Infrastructure Improvement Act (SIIA) was enacted on August 3, 1988, by the New Jersey Legislature (a State law only) in response to beach closings along the New Jersey coast during 1987 and 1988. One of the mandates of the SIIA was elimination of floatables and solids from CSOs, since CSOs were identified as the principal source of the beach debris. In addition to the mandate requiring solids/floatables reduction under the SIIA, the proposed project is required in order to comply with the General Permit for Combined Sewer Systems, NJPDES Permit Number NJ 01523. The CSO General Permit regulations were promulgated on January 27,1995, by the NJDEP in response to the USEPA's National CSO Control Strategy first proposed in 1989. The National CSO Control Policy, finalized by the USEPA in April 1994, divided implementation of the Policy into interim and long-term measures. The interim measures, commonly referred to as the Nine Minimum Controls, or NMCs, were proposed for implementation by January 1, 1997, while the Long-Term Control Plan could be developed over a period of years depending on the complexity of the combined sewer system.

The CSO General Permit regulations promulgated by the NJDEP incorporate EPA's CSO Control Policy provisions including the NMCs. One of the NMCs incorporated into the General Permit is the requirement to remove all floatables and solids greater than 1/2 inch. The proposed project is the direct result of the State and Federal mandates and is intended to satisfy the requirements for solids/floatables control at a minimum cost.

The existing combined sewer system for the City of Elizabeth is comprised of the following major components:

- approximately 150 miles of collector sewers
- approximately 2 miles of westerly interceptor sewer
- approximately 4 miles of easterly interceptor sewer
- 38 active CSO regulators
- 34 permitted CSO's
- 13 in-line storage modules
- 11 flushing modules

Within the City's combined sewer system, dry weather/base flow is collected by the sewer system and conveyed to the Trenton Avenue Pump Station (TAPS). From the TAPS, sewage is pumped to the Joint Meeting of Essex and Union Counties (JMEUC) Treatment Plant. The treated plant effluent from the JMEUC Treatment Plant is discharged to the Arthur Kill.

In the existing combined sewer system for the City of Elizabeth, wet weather flow is collected by the sewers and when the regulator capacity to the interceptor is exceeded, the flow is diverted to the CSO's, which are located along the Arthur Kill, Great Ditch, Newark Bay and Elizabeth River.

Included in the work under the preliminary design phase of the solids/floatables control facilities, a detailed inspection of each of the CSO regulators, storage and flushing modules was conducted. The purpose of the inspections and evaluations was to determine the current operating condition of each of the facilities and to undertake the required measurements and evaluations to determine the methods of retrofitting each of the facilities to provide for the required solids/floatables control. In addition to the inspection of the CSO regulators, storage and flushing modules, a survey of the two interceptor sewers was undertaken. The survey included determining as-built elevations and sewer sizes of the two interceptor sewers in order to utilize this data for the flow simulations.

The results of the inspections of the regulators, storage and flushing modules is summarized on Tables E.1. E.2 and E.3, respectively.

In order to calibrate the hydraulic simulation effort for the City's combined sewer system, meters were installed throughout the system to measure the combined sewer flow rates in the system during dry weather and wet weather conditions. From August 6, 1998 to October 20, 1998, twenty meters were installed at the metering sites located at strategic points throughout the system.

Twenty metering sites were selected to correspond to discrete sections of the hydraulic simulation prepared for analysis of the combined sewer system. Eight meters were located at sites along the Easterly Interceptor and twelve meters were located at sites along the Westerly Interceptor.

A proper assessment of the City's CSOs requires not only an understanding of existing systems and their hydraulic characteristics, but also a thorough understanding of the hydrology within the tributary drainage areas. Toward this understanding, areas tributary to each CSO system were delineated with respect to surface slope, soil types, percent imperviousness and land use. These analyses were facilitated through the use of a Geographical Information System (GIS), which served as the main platform for the synthesis of watershed data and the hydrologic/hydraulic analyses. Available data and reports which included information on drainage areas and land use, sewer system inventories and assessments and facilities inventories and assessments were utilized in the analysis.

Use was also made of the latest version of the USEPA SWMM model (Version 4.4) for the assessment of pipe flows.

City of Elizabeth - Design of Solids/Floatable Control Facilities
CSO Inspection List
Table E.1

Regulator Modules

Number	Type	Location	Date Inspected	Discharge Point	Regulator Type	Observed Condition
001	Primary	Routes 1 & 9 Northbound Entrance Ramp	05/28/98	Peripheral Ditch	Float & Gate	1, 2
002	Primary	Division Street @ Fairmont Avenue	05/28/98	Great Ditch	Float & Gate	1,2
003-A	Relief	Westfield Avenue @ Magie Avenue	05/27/98	Elizabeth River	Weir	3,4
003-B	Relief	Grove Street & Grand Avenue	06/18/98	Elizabeth River	Weir	3,4
005	Primary	Morris Avenue & Westfield Avenue	06/18/98	Elizabeth River	See Storage Module 1	
006	Primary	Union Street @ Crane Street	06/18/98	Elizabeth River	Orifice	13,7
007	Minor	West Grand @ Union/Price & River	06/18/98	Elizabeth River	Orifice	14
008	Minor	West Grand @ Elizabeth River	08/14/98	Elizabeth River	Orifice	14
009	Minor	Elizabethtown Plaza & Caldwell	06/17/98	Elizabeth River	Weir	
010	Primary	Cherry Street & Murray Street	06/16/98	Elizabeth River	Weir	
011	Primary	Rahway Avenue & Burnet Street	06/16/98	Elizabeth River	Vortex Valve	3,7
012	Minor	Rahway Avenue & Elizabethtown Plaza	06/17/98	Elizabeth River	Vortex Valve	
013	Primary	Burnet Street Near Rahway Avenue	08/15/98	Elizabeth River	Overflow	
014	Minor	South Broad Street & Elizabeth Avenue	06/17/98	Elizabeth River	Vortex Valve	3,7
016	Minor	Pearl Street & Washington Avenue	06/17/98	Elizabeth River	Weir	
017	Minor	Broad Street @ Elizabeth River	06/18/98	Elizabeth River	Weir	
021	Relief	Third Avenue between S. Spring & S. Reid Streets	05/28/98	Elizabeth River	Overflow	7
022	Primary	South Street , South Spring St. & 4th St.	06/16/98	Elizabeth River	Weir	
024	Minor	Norwood Terrace @ S. Pearl Street	06/18/98	Elizabeth River	n/a	12
025	Minor	S. Pearl Street & Montgomery Street	06/17/98	Elizabeth River	Overflow	15, 16
026	Primary	John Street (dead end) @ Elizabeth River	05/27/98	Elizabeth River	Float & Gate / Weir	1, 7
027	Primary	Summer Street & Clarkson Avenue	06/17/98	Elizabeth River	See Storage Module 7	
028	Relief	Summer Street & Clarkson Avenue	06/17/98	Elizabeth River	See Storage Module 7	
029	Primary	S. First Street @ Elizabeth Avenue (Waterfront Park)	05/27/98	Elizabeth River	Float & Gate	1
030	Relief	S. Front Street @ E. Jersey Street	06/01/98	Arthur Kill	Overflow	9
031	Primary	Livingston Street @ Front Street	06/01/98	Arthur Kill	Float & Gate	1
032	Primary	Front Street @ Magnolia Avenue	06/01/98	Arthur Kill	Float & Gate	1, 2
034-A	Primary	Atlanta Plaza (in parking lot)	05/29/98	Newark Bay	Float & Gate	5, 7, 10
034-B	Primary	Trumbull Street @ First Street	06/02/98	Newark Bay	Float & Gate	7
035	Primary	S. First Street @ Third Avenue	05/28/98	Elizabeth River	Float & Gate	1, 7, 8
036	Relief	intersections of N. Broad Street, Salem Avenue & Pingry Place	06/02/98	Elizabeth River	Overflow	
037	Primary	Bayway @ former S. Front Street (private road)	05/29/98	Arthur Kill	Float & Gate	1, 3
038	Relief	Third Avenue @ Atlantic Street (under NJ TPK. overpass)	06/01/98	Elizabeth River	Weir	11
039	Relief	Trumball Street @ Fourth Street	06/02/98	Great Ditch	Overflow	
040	Primary	Clifton Street @ Pulaski Street	05/28/98	Elizabeth River	Float & Gate / Weir	1, 3, 5, 6
041	Relief	Morris Avenue at Elizabeth River	06/18/98	Elizabeth River	See Storage Module 1A	
042A	Relief	Elizabeth Avenue & Bridge Street	06/17/98	Elizabeth River	Weir	3
042B	Relief	East Jersey Street & Winfield Scott Plaza	06/17/98	Elizabeth River	Weir	
042C	Relief	Jefferson Avenue & Chestnut Street	06/17/98	Elizabeth River	Weir	

** To be inspected by Killam. On 6/18/98 we could not inspect due to emergency repairs being performed to repair a collapsed main.
*** To be inspected by Killam.

Description of Observed Conditions

1 Float and gate mechanism appear to be "frozen" in the open position, allowing wet weather flows to enter the interceptor sewer.
2 Manhole frame(s) shifted from original position (not aligned with opening in chamber top slab)
3 No manhole steps in chamber.
4 Interior of chamber has been coated with gunite.
5 Grease accumulated on interior of chamber.
6 Manhole frame(s) cracked.
7 Sediment and debris accumulated on bottom of chamber.
8 Emergency overflow to the Great Ditch.
9 Outfall 030 was reportedly plugged and demolished at one time, then reconstructed with a tide gate and headwall in the marina along Waterfront Park.
10 Evidence of surcharging observed.
11 Weir damaged/partially eroded
12 The regulator is blocked. Flow goes directly into the interceptor.
13 Eighteen inch void in manhole base. It has been reported that the outfall line is collapsed.
14 Overflow pipe has a sluice gate which was observed open.
15 Tide gate is "frozen" in the open position.
16 Excessive infiltration was observed coming thru the tide gate.

ЛЕ.

City of Elizabeth - Design of Solids/Floatable Control Facilities
Storage Module Inspection Summary
Table E.2

Storage Modules

Module Number	Location	Observed Flap Gate Position	Observed Condition	Date Inspected	Discharge Point
S-1	Westfield Avenue @ Morris Avenue	Closed		06/18/98	Elizabeth River
S-1A	351 Morris Avenue	Closed		06/18/98	Elizabeth River
S-2	20 Sayre Street @ Elizabeth River (easement)	Closed	1, 2	06/03/98	Elizabeth River
S-3	Westfield Avenue @ Elizabeth River (easement)	Closed **	3, 4, 5	06/03/98	Elizabeth River
S-4	Dod Court @ Elizabeth River (easement)	Closed	1	06/03/98	Elizabeth River
S-5	Bridge Street @ Elizabeth River (easement)	Closed	6	06/03/98	Elizabeth River
S-7	Summer Street @ Clarkson Avenue	1/2 Open		06/17/98	Elizabeth River
S-8	927 Van Buren Avenue (near Alina Street)	Open	7	06/04/98	Peripheral Ditch
S-10	Alina Street @ Madison Avenue	Closed		06/18/98	Peripheral Ditch
S-11	Alina Street @ Jackson Avenue	Closed	8	06/04/98	Peripheral Ditch
S-12	Island @ intersection of Dowd Avenue & North Avenue East	2/3 Open	9	06/03/98	Great Ditch
S-13	Broadway @ Front Street	Closed	10	06/04/98	Arthur Kill
S-14	Third Avenue @ South First Street	Open	11,12	06/16/98	Elizabeth River

Note - As per previous reports, storage modules 6 & 9 do not exist.

** The flap gate in S-3 was found in the open position when inspection was started. DPW personnel closed the flap gate in the manual hand mode upon completing the inspection.

Description of Observed Conditions

1 Unit reportedly working properly according to DPW personnel.
2 Sediment accumulated on bottom of chamber.
3 Sanitary flows are pumped out of chamber.
4 Original concrete top slab has been removed and replaced with new slab which is not square to the chamber walls.
5 Only one out of four stainless steel screens are in place at stilling well.
6 Infiltration greater than approximately five gallons per minute observed in chamber.
7 Only one diversion manhole installed outside of chamber containing hydrobrake.
8 Dry (control) chamber is flooded and could not be inspected, reportedly from electric service to unit being terminated.
9 Main sewer line filled with approximately three feet of standing water.
10 Dry (control) chamber is flooded with over eleven feet of water and could not be inspected.
11 Dry (control) chamber is flooded with over ten feet of water and could not be inspected.
12 Did not access the chamber because Air Monitor Alarm. (O2 = 19.2 / LEL = 103 / HS = 2ppm)

City of Elizabeth - Design of Solids/Floatable Control Facilities
Flushing Module Inspection Summary
Table E.3

Flushing Modules

Module Number	Location	Observed Flap Gate Position	Observed Condition	Date Inspected
F-1	217 Catherine Street	Open	1A, 5	06/16/98
F-2	Reid Street @ East Grand Street	Open	1B	06/16/98
F-3	Reid Street @ East Jersey Street	Open	1C	06/16/98
F-4	Niles Street @ Third Avenue	½ Open	1D	06/05/98
F-6	719 Summer Street	Open	9	06/16/98
F-7	Fanny Street @ Madison Avenue	Open	2, 3	06/04/98
F-8	Adams Avenue @ North Avenue	Open		06/04/98
F-9	813 Van Buren Avenue (near North Avenue)	Open		06/04/98
F-10	Trumball Street @ Papetti Plaza	Open	7, 8	06/16/98
F-11	Front Street & Fulton Street	Open	2, 6	06/15/98
F-12	Third Avenue between Erie & Florida Street	Open	3, 4, 6	06/16/98

Note - flushing module 5 reportedly does not exist

Description of Observed Conditions

1A	Dry (control) chamber is flooded with over nine feet of water and could not be inspected.
1B	Dry (control) chamber is flooded with over six feet of water and could not be inspected.
1C	Dry (control) chamber is flooded with over eight feet of water and could not be inspected.
1D	Dry (control) chamber is flooded with over three feet of water and could not be inspected.
2	Evidence of water damage observed on interior of dry (equipment) chamber. Unit reportedly is not working properly.
3	Grease accumulated on interior of chamber.
4	Evidence of surcharging observed.
5	Manhole for chamber F004-2 was locked.
6	Some sediment in channel.
7	Outlet Sewer currently being lined by United Gunite.
8	Floatables in inlet chamber.
9	Chambers are exceptionally clean.

The first task in any hydrologic assessment consists of delineating the characteristics of a watershed, and its sub-basins, with respect to their soil type, land use, and slopes. This information was compiled through the use of layered templates using a GIS as a platform. The necessary information with respect to many of the aspects of the entire study domain and the sub-basins were provided by NJDEP and from data obtained by the City Engineer's Office.

The adaptation of SWMM to a complex drainage and conveyance system requires the calibration and verification of observed flows. This process requires two independent sets of data for pipe flows and rainfall, one set for calibration and the other set for verification. During calibration, the flow regime in the collection system is analyzed and friction factors for the system's pipes are assigned, along with hydraulic head losses at changes within the system. This objective is achieved through an iterative process wherein simulated flows are tested against observed flows.

The verification process follows a similar path to that of calibration. In this process, the second set of data is used to verify the accuracy of predictions based on model coefficients established during the calibration process. Usually, depending on the quality of the data sets used, it may be necessary to make minor adjustment to some coefficients and repeat the process until the desired comparison between simulated and observed flows is achieved.

Control alternatives to correct combined sewer overflow (CSO) discharges are usually classified into three (3) groups: (1) capital intensive alternatives, (2) minimal-structural alternatives, and (3) non-structural alternatives. The purpose of the preliminary design effort is to determine what control steps are required under Group 1 to meet the Sewage Infrastructure Improvement Act (SIIA). Due to the fact that earlier evaluations eliminated many alternatives and recommended a combination of sewer separations and static (underflow) bar screens, the evaluations undertaken as part of the preliminary design have been limited to the comparison of previously recommended improvements versus current state of the art alternatives of netting technology. Where applicable, other mechanical screening alternatives were reviewed on a case-by-case basis.

In accordance with the Sewage Infrastructure Improvement Act (SIIA), treatment facilities are to be provided at all active combined sewer overflows to remove solids and floatables. The SIIA guidelines require the removal of materials ½" and larger from the combined flow overflow discharge to the receding waters. NJDEP requires that treatment facilities be designed to treat the maximum flow capacity of the discharge pipe. Accordingly, the evaluation of the alternatives was based upon 100% removal of all solids/floatables greater than or equal to ½" at full pipe flow in the discharge pipe. The evaluation of alternatives was based primarily on the ability to implement the subject technology, removal effectiveness and capital/O&M costs.

A number of alternatives are available for implementation for long term control alternatives. The alternatives which were analyzed as part of the final selection process include:

- Sewer separation
- Static screens
- Netting technology
- Mechanical screens (including Romag screens)

With respect to the analysis of alternatives, sewer separation was only analyzed where feasible from an engineering standpoint. In addition, static screens were only analyzed for design flows of less than 20 MGD. For flows in excess of 20 MGD, the volume of solids resulting from high flow events would cause blinding of the static screens thereby resulting in unacceptable levels of upstream surcharging. An analysis was undertaken utilizing a standard Type III rainfall distribution to determine the total volume of solids that would result from various flowrates. In the analysis, the peak flow under consideration was assumed to occur at the peak period of the distribution. From this analysis, volumes of flow for the incremental hourly periods could be established. Using the relationship of solids/floatables equal to 2 cubic feet per million gallons of flow, a total volume of solids/floatables may be established. It has been shown that a 1/2" layer of solids/floatables would result in blinding of a static screen. From this relationship and the volumes calculated from the Type III storm event, a flow of 20 MGD will blind a screen area of approximately 160 square feet. Furthermore, the hydraulic analysis showed that even partial blinding of up to 50% of the screen area proposed under the previous design would result in unacceptable levels of surcharging upstream. For these reasons, the maximum flowrate of 20 MGD was established for the use of static bar screens.

All 34 CSOs were analyzed to determine the most cost effective alternative for providing solids/floatables control. The following general assumptions were utilized as part of the analysis:

- Construction cost estimates were developed based upon sites specific considerations including land availability, constructability, required utility relocations, need for easements, environmental considerations and other relevant factors. In addition, construction cost estimates included a 15% construction contingency due to the preliminary nature of the estimates and evaluations.

- Operation and maintenance costs were based upon information provided by equipment manufacturers and other available published information. In the case of the netting technology, O&M costs were based upon estimates for outside contract services performed by Fresh Creek.

- The cost analysis conducted for the various alternatives considered both initial capital costs and operation and maintenance costs for each alternative over a 20 year period. The present worth analysis was conducted at the present average cost of bonding which is approximately 4%. The present worth analysis also assumes that there would be no replacement or salvage of equipment during the 20 year period.

- The proposed treatment facilities for CSOs are anticipated to be in operation for an average of either 12 or 24 days per year, depending on design flowrate. High rate facilities (i.e. Flowrates greater than 20 MGD were assumed to require servicing/ maintenance 24 times per year. All other facilities would require maintenance 12 times per year.)

- Only construction and O&M costs were considered since the other costs including legal, administrative and engineering would all be a percentage of the estimated construction costs and therefore not result in altering comparison of alternatives.

The City previously planned to construct facilities which would control solids and floatables in the CSO System. However, due to concerns about the intended plans, a follow-up evaluation to assess new technologies was undertaken by Killam Associates. The detailed results of the follow-up evaluation and preliminary design is presented in Section 4 of this report. The evaluation demonstrated that three types of solids/floatables control facilities should be constructed. The proposed construction includes sewer separation, static bar screens and inline netting facilities. Table E.4 summarizes the recommendations including estimated construction cost and present worth cost for each of the CSO sites. The total cost for construction of the solids/floatables control facilities for the 34 CSO sites is estimated at approximately $11,610,000. In several cases, it is cost effective to construct multiple facilities for each CSO site in order to reduce the size of the facilities and accomodate the split flow from individual regulators. A total of 36 different sites are recommended for construction of solids/floatables controls and include five sites of sewer separation, twenty-six for inline netting facilities and five with static screening facilities.

The recommended construction described differs from the recommendations of the City's previous consulting engineer. In the earlier work, eight sites were recommended for sewer separation and twenty-five sites for static screening facilities. The analysis described in this report demonstrates that many of the sites which had been recommended for static screens have extremely high flow rates and would result in blinding of the static screens. Blinding of the static screens would cause surcharging and street flooding/overflows from the system. Furthermore, the concept of maintaining all solids/floatables within the system and concentrating them at the Trenton Avenue Pump Station was also reviewed. Based upon industry standards, the estimated total amount of solids/floatables which would result from an average of approximately 40" of rain per year is 130,000 lbs.. This entire amount of solids/floatables would have to be removed at the Trenton Avenue Pump Station. Based upon this high solids/floatables volume as well as significant concerns about concentrating solids/floatables within the system and at critical siphon crossings

City of Elizabeth - CSO Solids/Floatables Control Facilities

Table E.4 Summary Of Preliminary Design & Costs

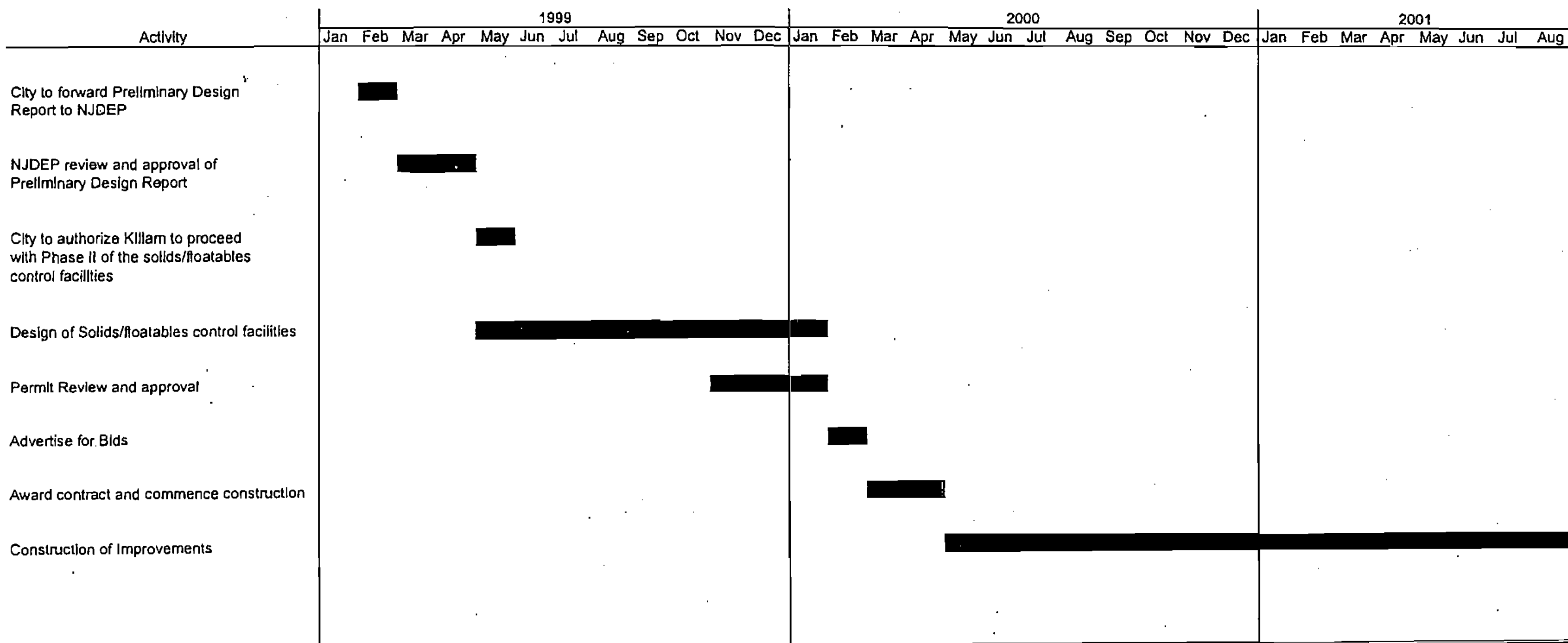
CSO Number	Recommended Alternative	Estimated Construction Cost	Present Worth of O&M Cost	Total Construction And O&M
001	In-Line Netting Facility	$490,000	$495,100	$985,100
002	In-Line Netting Facility	$430,000	$495,100	$925,100
003 A	In-Line Netting Facility	$710,000	$577,600	$1,287,600
003 B	In-Line Netting Facility	$420,000	$330,000	$750,000
005	In-Line Netting Facility	$450,000	$495,100	$945,100
007	Sewer Separation	$150,000	N/A	$150,000
008	Regulator & Static Bar Screen	$150,000	$34,400	$184,400
009	Sewer Separation	$30,000	N/A	$30,000
010	In-Line Netting Facility	$290,000	$330,000	$620,000
011	Sewer Separation	$40,000	N/A	$40,000
012	Regulator & Static Bar Screen	$160,000	$68,800	$228,800
013	In-Line Netting Facility	$240,000	$165,000	$405,000
014	In-Line Netting Facility	$370,000	$82,500	$452,500
016	In-Line Netting Facility	$310,000	$330,000	$640,000
017	Sewer Separation	$100,000	N/A	$100,000
021	Regulator & Static Bar Screen	$120,000	$34,400	$154,400
022	In-Line Netting Facility	$360,000	$495,100	$855,100
025	Sewer Separation	$210,000	N/A	$210,000
026	In-Line Netting Facility	$370,000	$495,100	$865,100
027	In-Line Netting Facility	$540,000	$660,100	$1,200,100
028	In-Line Netting Facility	$420,000	$495,100	$915,100
029	In-Line Netting Facility	$390,000	$495,100	$885,100
030	In-Line Netting Facility	$460,000	$660,100	$1,120,100
031	In-Line Netting Facility	$300,000	$330,000	$630,000
032	In-Line Netting Facility	$330,000	$330,000	$660,000
034	In-Line Netting Facility	$460,000	$660,100	$1,120,100
035	In-Line Netting Facility	$440,000	$660,100	$1,100,100
036	In-Line Netting Facility	$440,000	$660,100	$1,100,100
037	In-Line Netting Facility	$420,000	$495,100	$915,100
038	In-Line Netting Facility	$210,000	$165,000	$375,000
039	Regulator & Static Bar Screen	$170,000	$34,400	$204,400
040	In-Line Netting Facility	$450,000	$495,100	$945,100
041	In-Line Netting Facility	$620,000	$825,100	$1,445,100
042		CSO 42 Is Divided Into Three Overflow Locations: 042 A, 042 B, and 042 C		
042 A	In-Line Netting Facility	$220,000	$165,000	$385,000
042 B	Regulator & Static Bar Screen	$50,000	$41,300	$91,300
042 C	In-Line Netting Facility	$290,000	$330,000	$620,000
	Total Costs	**$11,610,000**	**$11,929,900**	**$23,539,900**

of the Elizabeth River, it was determined that static bar screens are inappropriate for installation at many sites. Furthermore, four sites (CSO 008, CSO 012, CSO 014 and CSO 016), which had been recommended for sewer separation previously were also deemed inappropriate due to significant concerns about additional surcharging resulting from adding flow to the interceptor sewers. At two sites, CSO 012 and CSO 014, flow monitoring conducted as part of this evaluation established that downstream and upstream interceptor sewers surcharged frequently even under low frequency storm events. For this reason, sewer separation at these two locations was eliminated and replaced by static screens and inline netting.

Upon review and agreement by City officials with the conclusions and recommendations of this report, the City must submit this Preliminary Design Report to NJDEP in accordance with the pre-award approval letter from NJDEP. The submission of this report will partially complete the requirements under the Long Term Solids/Floatables Control Measures of the General Permit. Following approval of the planned improvements by NJDEP, the City should authorize Killam Associates to initiate the final design or Phase II of the project. At the completion of Phase II, the City must complete a Stage II/III TWA application for submission to NJDEP. Following issuance of the TWA by NJDEP, the City would have 15 months to complete construction and commence operation of the long term solids/floatables control measures. A schedule outlining the project's milestones is included on Plate E.1.

One significant concern relative to the proposed facilities is the need to obtain easements from property owners and approvals from various agencies. Table E.5 is a summary of key issues relative to implementation of the solids/floatables control facilities as outlined in Section 4. The City should arrange to review these issues and initiate contacts with property owners where easements are required. One issue requiring immediate attention is implementation of solids/floatables control facilities in the Waterfront Park area. Reportedly, Green Acres funding was utilized for the development of Waterfront Park. As such, the Green Acres Program maintains jurisdiction for any proposed modifications to the park area. The recommendations presented in this report demonstrate the need for construction of netting facilities within or adjacent to Waterfront Park. In most cases, the need to construct the netting facilities is unavoidable in the

City of Elizabeth
Solids/Floatables Control Facilities
Plate E.1 - Milestone Implementation Schedule



City of Elizabeth - Preliminary Design of Solids/Floatable Control Facilities

Table E.5 - Summary of Key Issues for Design

Outfall Number	Location	Preliminary Design Improvement	City Actions Required
001	Routes 1 & 9 Northbound Entrance Ramp	Netting Facility	Possible Easement Required - Port Authority property
002	Division Street @ Fairmount Avenue	Netting Facility	Possible Easement Required
003-A	Westfield Avenue @ Magie Avenue	Netting Facility	
003-B	Grove Street & Grand Avenue	Netting Facility	Possible Easement Required - Parcel #13-1735
005	Morris Avenue & Westfield Avenue	Netting Facility	Possible Easement Required - Parcel #11-422
007	West Grand @ Union/Price & River	Sewer Separation	
008	West Grand @ Elizabeth River	Static Screen	
009	Elizabethtown Plaza & Caldwell	Sewer Separation	
010	Cherry Street & Murray Street	Netting Facility	Possible Easement Required - Parcel #6-159 (City of Elizabeth Housing Authority)
011	Rahway Avenue & Burnet Street (MH 15)	pipe to CSO 013	see CSO 013
012	Rahway Avenue & Elizabethtown Plaza (MH 12 & MH 13)	Static Screen	
013	Burnet Street Near Rahway Avenue	Netting Facility	Possible Easement Required
014	South Broad Street & Elizabeth Avenue	Netting Facility	
016	Pearl Street & Washington Avenue	Netting Facility	Possible Easement Required - Parcel #06-0860
017	Broad Street @ Elizabeth River	Sewer Separation	
021	Third Avenue between S. Spring & S. Reid Streets	Static Screen	
022	South Street , South Spring St. & 4th St.	Netting Facility	Possible Easement Required - Existing Pump Station Site
025	S. Pearl/Montgomery	Sewer Separation	
026	John Street (dead end) @ Elizabeth River	Netting Facility	
027	Summer at Arrnet	Netting Facility	Possible Easement Required - Parcel #4-59 (Union County Park Commission)
028	Summer at Arrnet	Netting Facility	Possible Easement Required - Parcel #4-372 (Union County Park Commission)
029	S. First Street @ Elizabeth Avenue (at gates to Waterfront Park)	Netting Facility	Waterfront Park, Green Acres Approval Required
030	S. Front Street @ E. Jersey Street	Netting Facility	Option "A" - Possible Easement Required - Parcel #2-478 (Marina); Option "B" Waterfront Park, Green Acres Approval - Parcel #2-479A
031	Livingston Street @ Front Street	Netting Facility	Waterfront Park, Green Acres Approval Required - Parcel #2-480
032	Front Street @ Magnolia Avenue	Netting Facility	Waterfront Park, Green Acres Approval Required - Parcel #1-167
034-A	Atlanta Plaza (in Atlantic Corp. parking lot)	Netting Facility	Possible Easement Required - Parcel #1-120
035	S. First Street @ Third Avenue	Netting Facility	Possible Easement Required - Parcel #2-857
036	intersections of N. Broad Street, Salem Avenue & Pingry Place	Netting Facility	Possible Easement Required
037	Bayway @ former S. Front Street (now a private road)	Netting Facility	Possible Easement Required
038	Third Avenue @ Atlantic Street (under NJ TPK. overpass)	Netting Facility	Possible Easement Required - Parcel #5-1353
039	Trumball Street @ Fourth Street	Netting Facility	
040	Clifton Street @ Pulaski Street	Netting Facility	Possible Easement Required - Parcel #4-1278 (Public School #22)
041	Morris Avenue at Elizabeth River	Netting Facility	Possible Easement Required - Parcel #11-679
042-A	Elizabeth Avenue @ Bridge Street	Netting Facility	
042-B	East Jersey Street @ Winfiled Scott Plaza	Netting Facility	
042-C	Jefferson Street @ Chestnut Street	Netting Facility	

Park area since the solids/floatables control facilities must be located between the regulator and the outfall structure. Since some of the regulators are located within the Park area, it is unavoidable to construct the required facilities in any location other than the Park. Due to this unavoidable circumstance, it is recommended that the City, with assistance from Killam Associates, immediately initiate discussions with representatives of Green Acres in order to determine actions to facilitate the construction of the solids/floatables control facilities. It is strongly recommended that the City take action immediately on this matter in order to prevent delays in implementation of the project. In addition, following the review of the preliminary design by NJDEP, it may be necessary to address other issues related to cultural resources. These issues will be addressed as part of the final design along with other permitting issues.

As part of the preliminary design, inspection of the City's CSO regulators, storage modules and flushing modules was undertaken. The results of the inspections indicate that many of the mechanical regulators are not functioning properly and require replacement and/or repair. In addition, the flushing and storage modules are inoperative due the lack of a central communication system and in some cases also require rehabilitation and repair. The hydraulic analysis of the system showed that the storage modules have little impact on reducing CSO flows, except under low flow conditions. Since the solids/floatable control facilities must be designed for all flow conditions, the presence or absence of storage modules has no impact on design.

1.1 Design Entity

The City of Elizabeth, located in the northeastern part of New Jersey in Union County, had a 1990 population of approximately 110,000. The City is a densely developed urban area consisting primarily of industrial development in the eastern portion and a mix of residential, commercial, institutional and light industrial development in the central and western portions. The central and western portions of the City are separated by the Elizabeth River and the Westerly Interceptor sewer, servicing these sections, parallels the river to its terminus at the Trenton Avenue Pumping Station. Port Elizabeth and Newark International Airport are located immediately to the City's northeast. The northeast and eastern portions of the City are serviced by the Easterly Interceptor sewer which also terminates at the Trenton Avenue Pumping Station. The Trenton Avenue Pumping Station, in turn, discharges wastes to the Joint Meeting of Essex and Union Counties' wastewater treatment plant.

The City of Elizabeth owns, and through its Department of Public Works, operates a combined sewer system, which, during dry weather, discharges wastewater to the Joint Meeting of Essex and Union Counties (JMEUC) wastewater treatment plant located in Elizabeth. The JMEUC's wastewater treatment plant has an average design flow of 85 MGD, provides secondary treatment and services Elizabeth and fifteen surrounding municipalities. Elizabeth's sewer system is sixty-eight percent combined (sanitary sewage and stormwater runoff in a common pipe) and is reported to be between 50 and 100 years old. The combined sewer system collects wastewater and stormwater from approximately 4,250 acres and presently contains 34 combined sewer overflows (CSOs). The CSOs are activated during storm events and discharge diluted raw sewage to the receiving water bodies surrounding the City. Such overflows were calculated to occur, on average, 70 times per year. Twenty-five CSOs discharge to the Elizabeth River, five to the Arthur Kill, two to the Great Ditch and one each to the Newark International Airport Peripheral Ditch and Newark Bay.

1.2 Legislative Mandate

In order to place the proposed project in perspective, it is instructive to review the history of the enabling legislation requiring implementation of the project and the National Policy developed by the U.S. Environmental Protection Agency (USEPA). The Sewage Infrastructure Improvement Act (SIIA) was enacted on August 3, 1988, by the New Jersey Legislature (a State law only) in response to beach closings along the New Jersey coast during 1987 and 1988. The beach closing were caused by unsightly, unsanitary and potentially hazardous debris washing up onto public beaches. One of the mandates of the SIIA was elimination of floatables and solids from CSOs since CSOs were identified as the principal source of the beach debris. Among other things, the SIIA authorized ninety percent grants to municipalities for the planning and design of solids/floatables control facilities at CSO points. The City of Elizabeth received a 90 percent planning grant and authorized its consulting engineer to prepare the required planning report.

In addition to the mandate requiring solids/floatables reduction under the SIIA, the proposed project is required in order to comply with the General Permit for Combined Sewer Systems, NJPDES Permit Number NJ 01523. A copy of the City's General Permit is included in Appendix A. The CSO General Permit regulations were promulgated on January 27,1995, by the NJDEP in response to the USEPA's National CSO Control Strategy first proposed in 1989. The National CSO Control Policy, finalized by the USEPA in April 1994, divided implementation of the Policy into interim and long-term measures. The interim measures, commonly referred to as the Nine Minimum Controls, or NMCs, were proposed for implementation by January 1, 1997, while the Long-Term Control Plan could be developed over a period of years depending on the complexity of the combined sewer system. The NMCs are intended to be implemented in the short term, require minimum expenditure of funds and provide an initial reduction in pollutants emanating from CSOs. In brief, the NMCs include:

- implementation of an effective operation and maintenance program;
- maximization of available sewer system internal storage;
- maximization of flow to treatment;

- effective implementation and enforcement of the industrial pretreatment program;
- elimination of dry weather overflows;
- provisions for solids/floatables reduction;
- development of pollution prevention plans;
- monitoring of receiving waters;
- public notification of the impacts of CSOs.

The CSO General Permit regulations promulgated by the NJDEP incorporate EPA's CSO Control Policy provisions including the NMCs. One of the NMCs incorporated into the General Permit is the requirement to remove all floatables and solids greater than 1/2 inch from all CSOs which, fortuitously, is the subject of the SIIA and for which State grants are available. The proposed project is the direct result of the State and Federal mandates and is intended to satisfy the requirements for solids/floatables control at a minimum cost. However, design of the proposed project also incorporates several of the other NMCs, namely,

- Elimination of dry weather overflows including receiving water body intrusion into the sewer system;
- maximization of temporary sewer system storage;
- maximization of flows to the treatment plant.

While the proposed project will satisfy solids/floatables reduction, as well as several other NMCs, the project must be viewed in the context of the Long-Term Control Plan (LTCP) requirements. In brief, the LTCP development, for which neither grant nor loan funds are available, requires:

- characterization, monitoring and modeling of the sewer system and CSOs;
- public participation and agency interaction;
- an evaluation of:
  - sensitive areas
  - alternative approaches to achieve water quality standards
  - presumptive approach
  - demonstrative approach
  - cost effectiveness analysis

- development of an operational plan;
- maximization of flow to treatment
- development of an implementation schedule
- post-construction compliance monitoring

In theory, the LTCP will develop a mathematical model of the combined sewer system's response to storm events. The calibrated and verified model will be able to predict the quantity and quality of CSOs for any storm event except hurricanes or other natural disasters. The sewer system model can be considered the "landside" model. The "waterside" model will, in all likelihood, be developed by the NJDEP or by a consultant under contract to the DEP. In the ideal case, the NJDEP will exercise its model for various storm events and require the City to exercise its model for the chosen or design storm event. The City's model will predict the quality and quantity of overflows and the DEP model will predict whether or not water quality standards are achieved. In the event that water quality standards are not achieved, the DEP may require further treatment (beyond solids/floatables reduction) or a reduction in the quantity of CSOs. The former requirement could result in additional treatment by the City (e.g., disinfection or suspended solids reduction) or construction of storage facilities (either in-line or off-line). It is the possibility for future CSO control facilities that makes it imperative that *the* cost effective, environmentally sound solids/floatables control facilities be designed and constructed at this time.

1.3 Project History and Development

In the early 1970's the Joint Meeting of Essex and Union Counties (JMEUC) received a grant award from the USEPA to upgrade its treatment plant to secondary treatment. A special condition of the grant required:

> " The grantee [JMEUC] shall submit to the New Jersey State Department of Environmental Protection (NJSDEP) and the Environmental Protection Agency (EPA) by October 1, 1973, a resolution adopted by the City of Elizabeth setting

> forth its agreement to study the combined sewer system within the City, to identify alternative corrective programs, to select the most cost-effective solution in compliance with the requirements of the NJSDEP and EPA and to establish an effective schedule for implementing the most desirable alternative."

The City indeed adopted such a resolution, applied for and received an EPA Demonstration Grant (#S-802971) and proceeded to have its engineering consultant study and report on a "Comparison of Alternative Sewer Designs for Municipal Wastes and Urban Runoff."

The study and report were completed in 1976 and included in an EPA publication entitled, "Conventional and Advanced Sewer Design Concepts for Dual Purpose Flood and Pollution Control - A Preliminary Case Study, Elizabeth, NJ," EPA Report No. EPA-600/2-78-096, May 1978. The EPA publication addressed items such as pollution caused by combined sewers versus separate storm and sanitary sewers, in-line storage of wet weather flows, deposition of solids during dry weather in large combined sewers with relatively flat slopes, the theoretical pollutant loads produced by the first flush during storm events, etc. Of particular interest to the next phase in the evolution of Elizabeth's combined sewer system were the findings:

- "Capture of the low volume, high-concentration first flush from combined systems is essential for pollution abatement....
- Storage of combined sewage should reduce pollutant concentration as a result of mixing the highly polluted first flush with later, less polluted flows. Storage is effective in abating pollution."

The City of Elizabeth, based on the studies and reports produced during the late 70's, acknowledged that its combined sewer overflows were one factor contributing to the pollution of the Elizabeth River and other surrounding water bodies. The City authorized its consulting engineering firm, Clinton Bogert Associates (CBA), to undertake a comprehensive analysis of the City's sewer system and recommend a phased program to control or minimize the adverse impacts of its CSOs. The end result of this effort was a report dated August 1981 by CBA entitled, "Combined Sewer

Overflow Pollution Abatement Program." After review by the City, the NJDEP and USEPA, the report was revised in April 1986 and recommended a comprehensive program for CSO control including the phased construction of combined sewer flushing modules, in-line storage modules, off-line underground storage tanks, storm sewer in-line storage modules and a centralized control system to monitor and remotely activate the multiple control facilities.

Once accepted and approved by the City, NJDEP and the USEPA, the first phase of construction was completed in the early 1990's and included construction of thirteen in-line storage modules, eleven flushing modules and capacity increase for the Westerly Interceptor sewer. These internal facilities were designed to minimize the volume of CSOs, as well as reduce the concentration of conventional pollutants (e.g., BOD, SS, nutrients) discharged during storm events. It should be noted that the storage and flushing modules did nothing to remove solids and floatables, nor were they required nor designed to do so.

During this same time period, namely, the early 1990's, the State of New Jersey, through the DEP, began implementing the Sewage Infrastructure Improvement Act (SIIA), while the USEPA was attempting to finalize its National Strategy for Combined Sewer Overflows (see Section 1.2 above). The SIIA authorized 90 percent State grants for the planning and design of solids/floatables control facilities and low interest loans for construction. As a result of the availability of funds under the SIIA program and the need to update its 1986 report to address solids/floatables control, the City applied for and received a planning grant (CSO-91-017). The resulting report entitled, "Report to the City of Elizabeth, Combined Sewer Overflow Abatement Strategy, Solids/Floatables Reduction at Combined Sewer Overflow Points," was prepared by CBA and dated June 1993.

In keeping with the spirit and intent of the earlier studies, and in an effort to reduce the solids loadings and thus pollutants to the receiving waters, the June 1993 report recommended diversion and screening facilities for "primary" and "relief" outfalls, construction of swirl separators to capture the "first flush" and reduce solids/floatables at the primary outfalls, and sewer separation at the "minor" outfalls. The recommended facilities had a construction cost estimated by CBA at $20,690,000 (1993 dollars) including a 20 percent contingency.

The NJDEP reviewed the planning report and raised significant questions in its letter to the City dated October 13, 1993. CBA, on behalf of the City, responded to the DEP's letter in a submission dated November 22, 1993. During the next sixteen months, a series of discussions and exchanges of correspondence took place among the City, its consulting engineer and the NJDEP. These exchanges resulted in the submission, under cover letter dated March 30, 1995, signed by Herbert L. Kaufman, of a "Project Report Addendum." The Addendum revised the proposed facilities by essentially eliminating the first flush swirl separators and associated appurtenances but retaining the diversion facilities and underflow bar screens. Elimination of the swirl separators reduced the construction cost estimate to $8,559,000 (1993 dollars). In its Environmental Summary dated May 16, 1996, the NJDEP addressed elimination of the first flush swirl separators and the other final alternative by stating, "The remaining alternatives evaluated were the swirl separator and rotating drum screen. However, these alternatives <u>were determined to be unnecessary in meeting the current Department requirements for CSO abatement</u> and were also eliminated from consideration" (underlining added).

The resulting project, approved by the NJDEP, grouped the proposed facilities into three categories, namely, primary, relief and minor outfalls. Fifteen diversion and screening facilities, along with an extensive array of appurtenances, were recommended for the primary outfalls including modifications to four existing storage module flap gates. Twelve manually cleaned bar screens were proposed for the relief outfalls, along with modifications to the hydraulic controls on four additional storage module flap gates. The final recommendation included separation of the combined sewers at minor outfalls, thereby eliminating CSOs, by constructing approximately two miles of new separate sanitary and storm sewers.

Between May 1996, the date the NJDEP published its Environmental Summary, and April 6, 1998, the date the NJDEP notified the City of Elizabeth of pre-award approval for design of the project under the Sewage Infrastructure Improvement Act, several significant developments took place which had an impact on the proposed project. The firm Clinton Bogert Associates went out of business and was temporarily replaced by Kaufman Engineering under the leadership of Herbert L. Kaufman, a former principal in CBA. In 1996 the City engaged Killam Associates to design the proposed project including preparation of a design report, plans, specifications and contract documents. During 1997 the City, with assistance from Killam Associates, met with the NJDEP several times to negotiate and clarify the Scope of Services for Design and establish a schedule and approach towards satisfying the solids/floatables control requirements.

The agreed upon Scope of Services for professional engineering services is detailed in Killam Associates' proposal to the City dated October 14, 1997, and clarified in Killam Associates' letter to Stanley V. Cach, Jr., dated March 5, 1998. The Scope of Services describes the design as two separate and distinct phases. This Preliminary Design Report represents the conclusion of Phase I and is being prepared for review by officials within the City and at the NJDEP. In its pre-award approval letter dated April 6, 1998, the NJDEP stated:

> "(1) The City shall submit to this office phase I work in accordance with the scope of work contained in the proposal. If the final concept differs from the Department approved Plan, a revised Environmental Decision Document will be required prior to approving Phase I work.
>
> (2) The City shall not initiate and prepare partial or final contract documents or initiate phase II work prior to our [NJDEP] approval of phase I work.
>
> (3) Upon receipt of our [NJDEP] written approval on phase I work, the City shall prepare and submit to this office phase II work in accordance with the scope of work contained in the proposal."

The balance of this Preliminary Design Report sets forth the background, hydraulic/hydrologic assessment and preliminary design for the solids/floatables control facilities.

2.1 Description of Existing Systems

Originally constructed in the late 1800's, the sewer system for the City of Elizabeth consisted of one combined sewer system that collected both sanitary and storm flows and discharged the flow directly into the adjacent waterways. Combined flows from the eastern portion of the City discharged the flow to the Arthur Kill, Great Ditch or Newark Bay and combined flows from the western and central portions of the City discharged to the Elizabeth River.

In 1898, the Essex-Union Joint Meeting (EUJM) was created to reduce pollutant discharge to waterways and new sewers were constructed to intercept dry weather/base flows and prevent the flows from being discharged to adjacent waterways. This was accomplished by constructing interceptor sewers to bisect each of the outfall pipes and constructing regulators to divert the flow for treatment. Two separate interceptor sewers were constructed in the City of Elizabeth to serve the easterly and westerly portions of the City. Regulators were constructed in-line with the existing outfall piping at locations near the interceptor sewer to control the flow into the interceptor sewers.

Several modifications and improvements to the City's sewer system were constructed over the years which included the construction of dedicated sanitary sewers, storm sewers and relief storm sewers. The most recent improvement to the sewer system consisted of the construction of in-line storage and flushing modules in 1990, which were designed to reduce pollutant discharge to the adjacent waterways.

The Sewer System Map of the City of Elizabeth -Plate 2.1 shows the location of the combined sewers, storm sewers, interceptor sewers, Joint Meeting Sewers (JMS), regulators, storage modules, flushing modules and CSO outfalls. Plans of the easterly and westerly interceptor sewers are shown on Plates 2.5 and 2.6, respectively.

2.1.1 Sanitary/Combined Sewer System

The existing combined sewer system for the City of Elizabeth is comprised of the following major components:

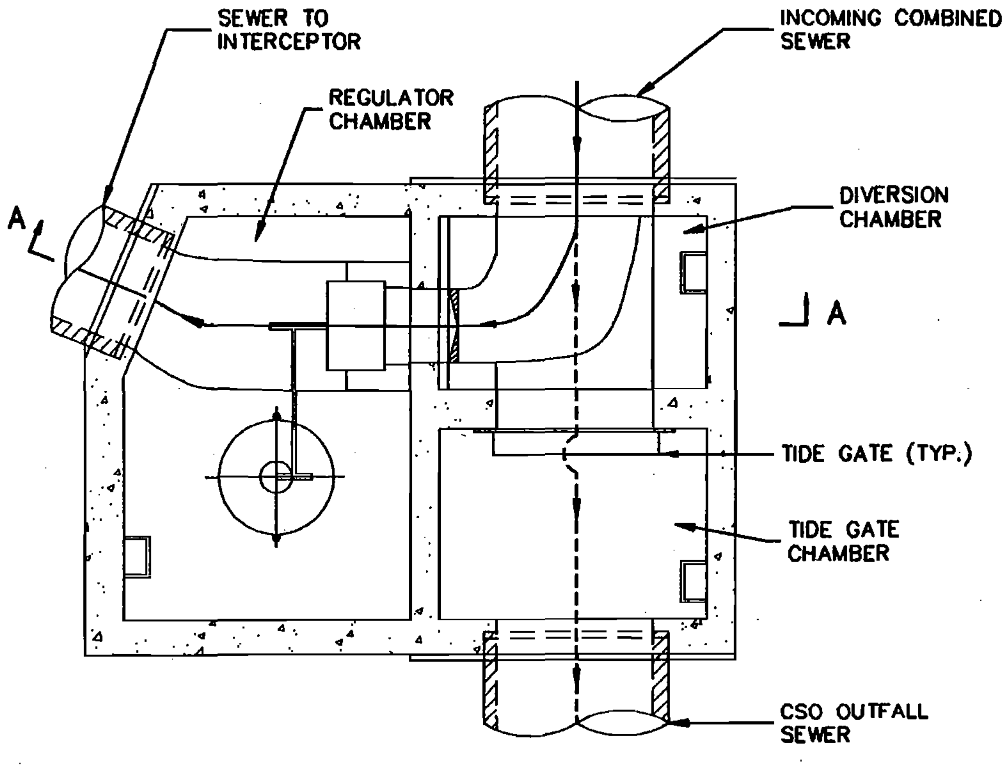
- approximately 150 miles of collector sewers
- approximately 2 miles of westerly interceptor sewer
- approximately 4 miles of easterly interceptor sewer
- 38 active CSO regulators
- 34 permitted CSO's
- 13 in-line storage modules
- 11 flushing modules

Within the City's combined sewer system, dry weather/base flow is collected by the sewer system and conveyed to the Trenton Avenue Pump Station (TAPS). From the TAPS, sewage is pumped to the Joint Meeting of Essex and Union Counties (JMEUC) Treatment Plant. The JMEUC Treatment Plant is located in the City of Elizabeth on South First Street in the southwest portion of the City. The treated plant effluent from the JMEUC Treatment Plant is discharged to the Arthur Kill.

In the existing combined sewer system for the City of Elizabeth, wet weather flow is collected by the sewers and when the regulator capacity to the interceptor is exceeded, the flow is diverted to the CSO's which are located along the Arthur Kill, Great Ditch, Newark Bay and Elizabeth River .

2.1.2 CSO Regulators

The intended purpose of the CSO regulators is to route dry weather/base flows to the interceptor sewer and divert wet weather flows to the CSO outlet. Within the City of Elizabeth's combined sewer system, the diversion of combined sewer flows is accomplished by either mechanical (moving parts) regulators or non-mechanical (no moving parts) regulators.



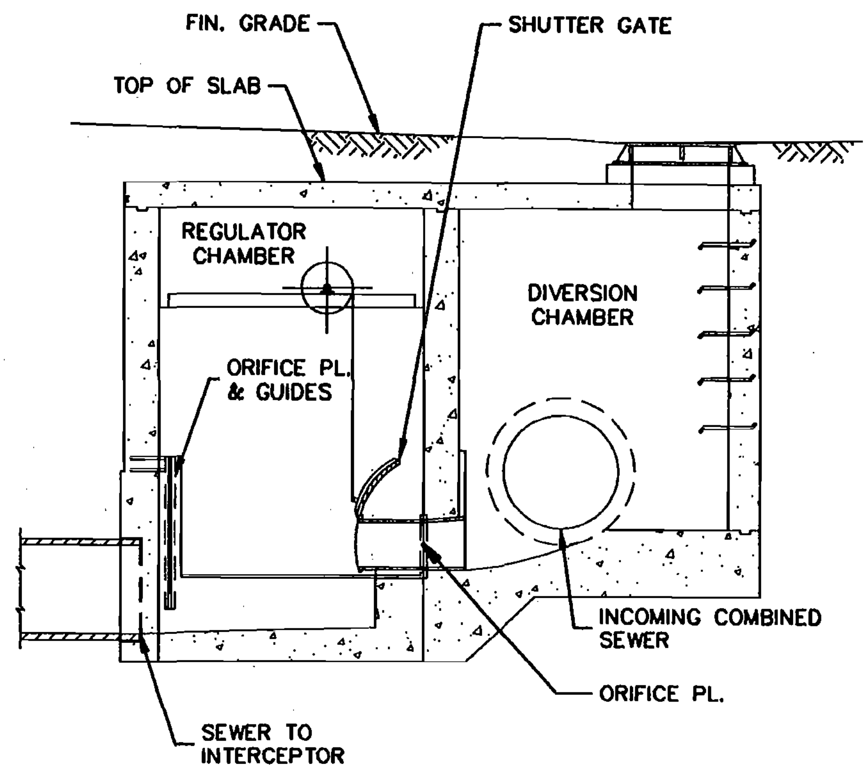
SECTIONAL PLAN

NOT TO SCALE

LEGEND

——→ DRY WEATHER FLOW

- - - - → WET WEATHER FLOW



SECTION A–A

NOT TO SCALE

Killam
Associates ▫ Consulting Engineers

27 Bleeker Street
Millburn, New Jersey 07041

CITY OF ELIZABETH
UNION COUNTY, NEW JERSEY

CSO SOLIDS/FLOATABLES CONTROL FACILITITES

PLATE 2.2 TYPICAL REGULATOR SCHEMATIC

Designed	Drawn	Checked	Approved	Date	Scale
J.J.M.	J.J.M.	J.A.F.			N.T.S.

The mechanical regulators consist of float operated gates that were originally designed to isolate the CSO's outlets from the interceptors during wet weather flows. A typical mechanical regulator consists of the following interconnected subsurface concrete chambers: 1) diversion chamber; 2) regulator chamber; and 3) tide gate chamber. Plate 2.2 is a plan and section drawing of a typical mechanical regulator.

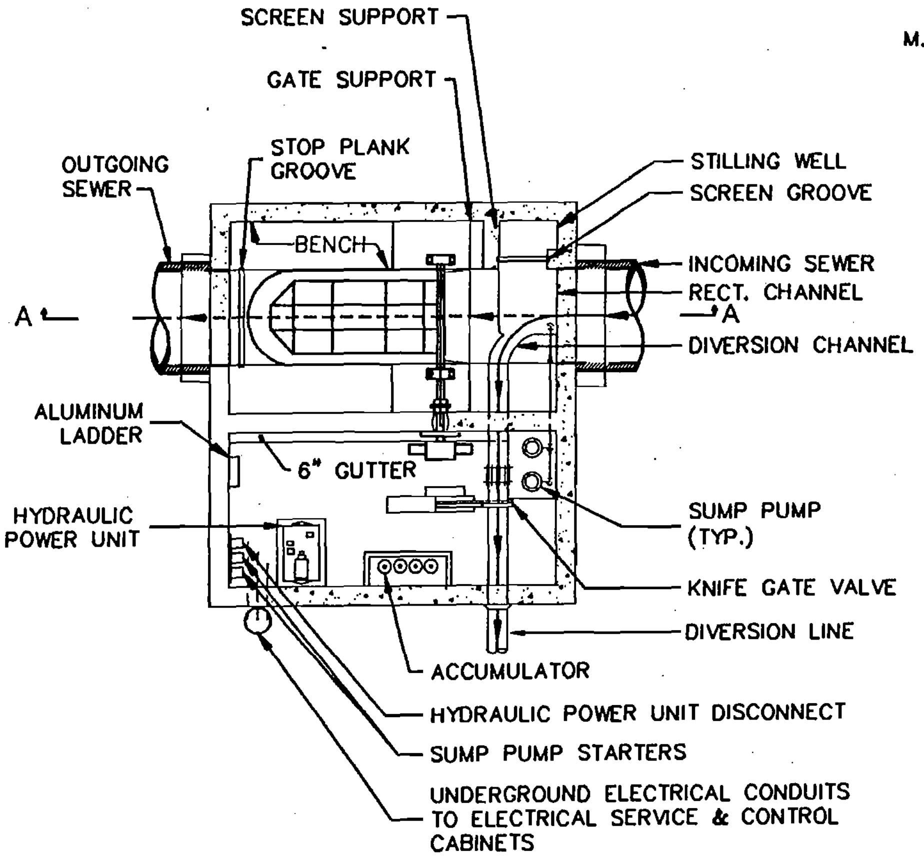
Within the mechanical regulator, the diversion chamber contains a concrete channel to divert the dry weather/base flow to the regulator chamber, which regulates flow to the interceptor. When wet weather flow surcharges the diversion chamber, the flow discharges thru the tide gate chamber to the CSO. A tide gate is typically located in the tide gate chamber, however, in some cases, the tide gate is installed at the end of the CSO outfall pipe.

The regulator chamber of a mechanical regulator contains a float and regulator/shutter gate assembly to control the flow from the diversion chamber to regulator chamber and interceptor sewer. When wet weather flows occur, the regulator chamber surcharges, raising the float assembly and closing the shutter gate preventing flow to the interceptor and surcharging the diversion chamber. An orifice plate and guides are also installed over the sewer to the interceptor to facilitate manually stopping flow to the interceptor.

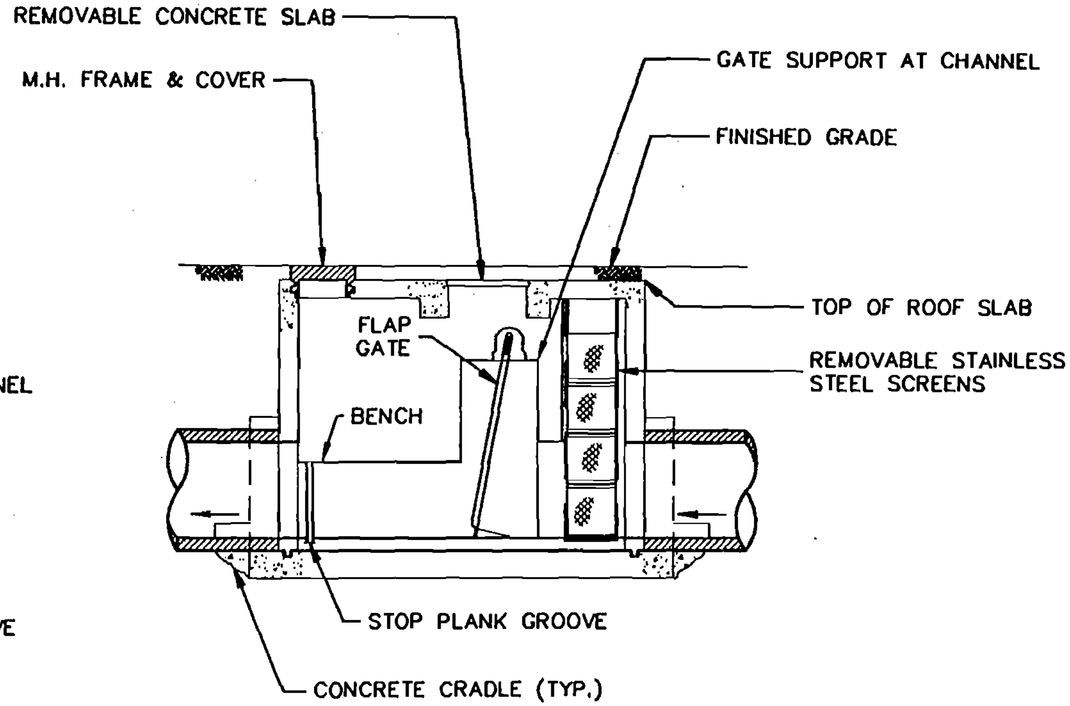
Approximately one-third of the CSO regulators in the City of Elizabeth's sewer system are mechanical regulators, which are predominately used for primary outfalls.

Non-mechanical regulators operate based on higher overflow elevations in the system. When the wet weather flow surcharges in the system, the non-mechanical regulators use weirs, orifices, vortex valves or pipe invert elevations to control the diversion of wet weather flow. Non-mechanical regulators appear to be used predominantly for relief outfalls.

Information concerning the location, configuration and condition of each of the CSO regulators is included in Section 2.2 of this report.



SECTIONAL PLAN
NOT TO SCALE



SECTION A–A
NOT TO SCALE

LEGEND
→ DRY WEATHER FLOW
- - → WET WEATHER FLOW

Killam
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27 Bleeker Street
Millburn, New Jersey 07041

CITY OF ELIZABETH
UNION COUNTY, NEW JERSEY
CSO SOLIDS/FLOATABLES CONTROL FACILITITES

PLATE 2.3 TYPICAL STORAGE MODEL SCHEMATIC

Designed	Drawn	Checked	Approved	Date	Scale
J.J.M.	J.J.M.	J.A.F.			N.T.S.

2.1.4 Flushing Facilities

The intended purpose of flushing facilities is to limit pollutant discharge to the overflow waterway. The flushing facilities reduce the impact of the "first flush" (highest pollutant concentration) by periodically flushing targeted combined sewer segments to limit the accumulation of deposits in combined sewers with limiting slopes.

The flushing facilities were designed concurrently with the storage modules under Contract 21 by Clinton Bogert Associates in 1988 and were constructed in 1990. Plate 2.4 is a typical plan and section drawing of the flushing modules installed in the City's sewer system.

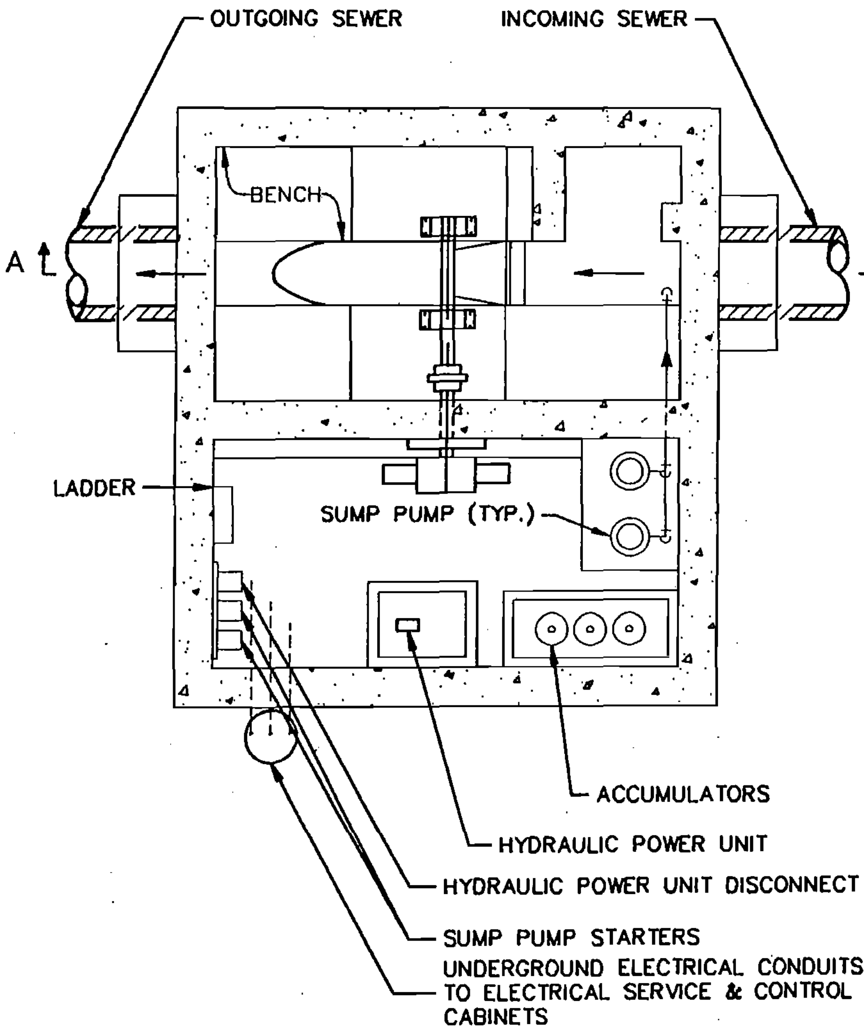
The flushing facilities are configured in a similar manner as the storage modules, but the flushing module does not divert flow from the in-line sewer. The operation of the flushing module consists of the in-line flap gate opening and closing to flush the combined sewer. The flushing facilities were intended to be controlled remotely by radio.

A summary of the locations, configurations and conditions of the flushing modules is included in Section 2.2 of this report.

2.1.5 Pumping Facilities

The City's main sanitary\combined pumping station is the Trenton Avenue Pumping Station (TAPS) which is located adjacent to Trenton Avenue. The TAPS accepts sanitary/combined flows from both the easterly and westerly interceptor sewers and pumps the sewage to the JMEUC Treatment Facility. All wastewater flows from the City must pass through the TAPS for discharge to the JMEUC.

The TAPS is equipped with two mechanically cleaned bar screens. Flow to the facility is regulated during wet weather periods utilizing two motorized sluice gates. The facility is equipped with a



SECTIONAL PLAN
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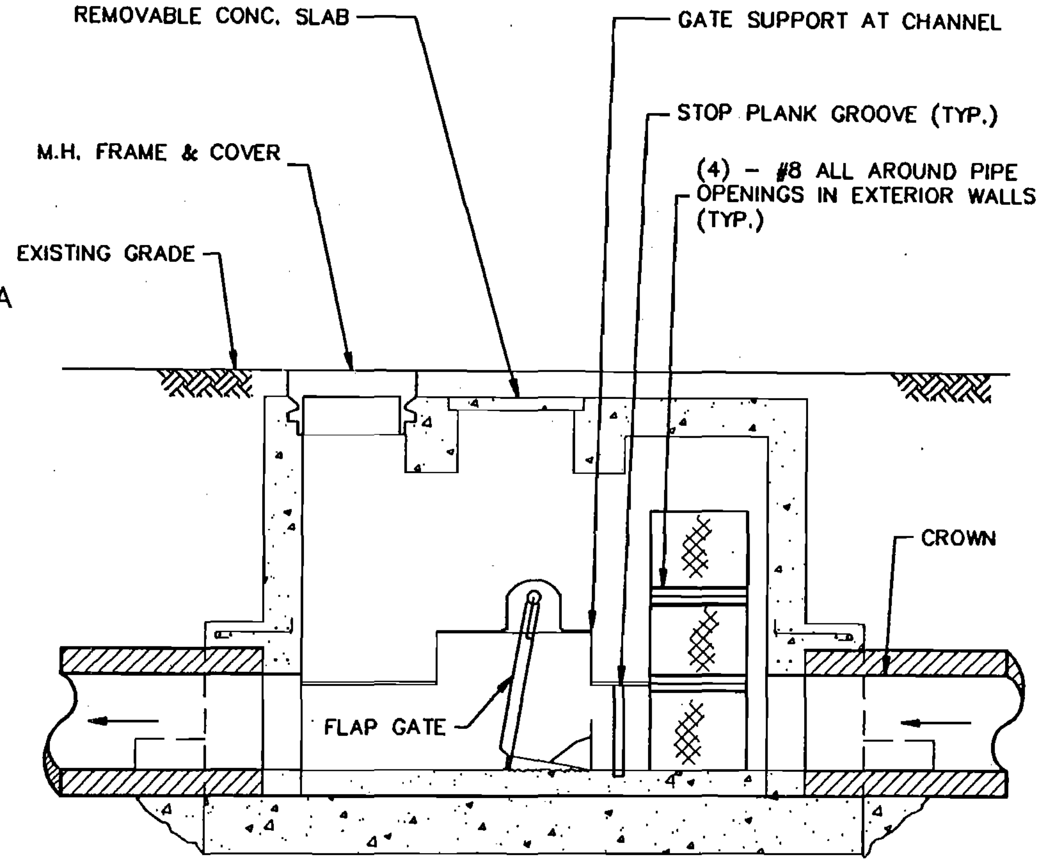

SECTION A–A
NOT TO SCALE

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CITY OF ELIZABETH
UNION COUNTY, NEW JERSEY

CSO SOLIDS/FLOATABLES
CONTROL FACILITITES

PLATE 2.4 TYPICAL FLUSHING MODULE SCHEMATIC

Designed	Drawn	Checked	Approved	Date	Scale
J.J.M.	J.J.M.	J.A.F.			N.T.S.

total of five pumps. Pump No. 1 is rated at 10 MGD and is equipped with a 75 Hp motor. Pump Nos. 2 through 5 are rated at 13 MGD and are equipped with 100 Hp motors. Pump Nos. 3 & 4 are equipped with variable frequency drives in order to regulate flow from the facility.

The agreement between the City of Elizabeth and the JMEUC limits discharges from the City of Elizabeth to the JMEUC Plant to 25 MGD. Flows in excess of 25 MGD will result in excessively high flows and flooding at the JMEUC Treatment Plant. As such, during high flow events, the City will regulate flow from the TAPS with the maximum flow not exceeding the 25 MGD limitation and will regulate wastewater flow into the station by regulating the motorized sluice gates on the effluent of the facility. The regulation of the sluice gates results in the utilization of the interceptor sewer as a storage vessel thereby maximizing the amount of flow which may be discharged to the JMEUC treatment facility for subsequent treatment.

2.1.6 CSO Discharge Permit

The City of Elizabeth was issued a New Jersey Pollutant Discharge Elimination System Individual NJPDES/DSW General Permit No. NJ0108782 on June 30, 1995. This permit was an individual CSO Discharge Permit and also embodied the provisions of the general permit authorization under the General Permit for Combined Sewer Systems, NJPDES Permit No. NJ0105023. With the issuance of the aforementioned permits, the City's previous permit for operation of the CSO System was terminated.

The individual permit authorization allows the City to operate a combined sewer system for the collection and conveyance of wastewater and to discharge untreated wastewater in the form of combined sewer overflows from the combined sewer overflow points located throughout the City as listed in the permit. A copy of the Individual and General Permit for the City's CSO System is included in Appendix A.

The New Jersey Pollutant Discharge Elimination System General Permit No. NJ0105023 for combined sewer systems includes a number of provisions which are applicable to the installation of solids/floatables control facilities which are the subject of this report. Of particular importance is the timetable set forth in the General Permit for the installation of interim solids/floatable control measures and long term solids/floatables control measures. Due to the fact that the facilities under consideration for installation by the City at this time are considered long term solids/floatables control measures, discussions included herein will only reference the timetable for long term control measures. Under Section D- Solids/Floatables, Subsection 2- Long Term Solids/Floatables Control Measures, the General Permit outlines the time frame for certain actions to be taken. The permit requires the permit holder submit an approvable long term solids/floatables control measures plan to the Department on or before March 1, 1996. Following the review and comments by NJDEP, the permittee is required to modify the previous submission to comply with the Department's comments and resubmit the plan for final approval by NJDEP. Following the receipt of approval by NJDEP, the permittee is to undertake the design and submit an administratively complete Stage II/III TWA Application to NJDEP for approval. Following the receipt of approval of the TWA Application, the permittee is to complete construction and commence operation of the approved long term solids/floatables control measures within 15 months.

While the City has not met the deadlines required by the General Permit, the City has been actively working toward meeting the requirements and this report will serve as the intended plan for the long term solids/floatables control measures. The City intends to immediately proceed with the preparation of final plans and specifications and the submittal of the required TWA Application to NJDEP, following the approval by the Department of the plan.

2.2 Field Investigations

Included in our work under the preliminary design phase of the solids\floatables control facilities, a detailed inspection of each of the CSO regulators, storage and flushing modules was conducted. The purpose of the inspections and evaluations was to determine the current operating condition of each of the facilities and to undertake the required measurements and evaluations to determine the methods of retrofitting each of the facilities to provide for the required solids/floatables control. In addition to the inspection of the CSO regulators, storage and flushing modules, a survey of the two interceptor sewers was undertaken. The survey included determining as-built elevations and sewer sizes of the two interceptor sewers in order to utilize this data for the flow simulations. The sections which follow provide descriptions of each component of the City's combined sewer system and appurtenances.

2.2.1 Easterly Interceptor Sewer

The easterly interceptor sewer is approximately four miles in length and ranges from 33" to 60" diameter sewers. The easterly interceptor sewer begins at a point in the general vicinity of CSO 001 as a 33"ϕ and extends along Dowd Avenue through right-of-way areas adjacent to Trumbull Street as a 42"ϕ sewer. The interceptor continues to Front Street as 48"ϕ and 54"ϕ sewers and ultimately terminates at the Trenton Avenue Pump Station via First Street with the sewer size ranging from 54"ϕ to 60"ϕ. An overall plan of the easterly interceptor is included on Plate 2.5. Plate 2.5 details the size of the interceptor sewer along its alignment and also includes invert and rim elevations at key manholes.

2.2.2 Westerly Interceptor Sewer

The westerly interceptor sewer is approximately two miles in length and consists of mostly brick sewers. The westerly interceptor sewer begins at the intersection of Westfield Avenue and Union Street and extends along Union Street to Elizabeth Avenue and crosses the Elizabeth River in the vicinity of Bridge Street. At this location the westerly interceptor sewer joins with a branch portion of the interceptor sewer that extends upstream along Pearl Street and Cherry Street. The westerly interceptor sewer extends from Bridge Street along South Pearl Street and Clarkson Avenue as a 36" brick sewer and continues along the Elizabeth River corridor adjacent to Mattano Park before terminating at the Trenton Avenue Pump Station as a 60" sewer. A plan of the westerly interceptor

continued

sewer is shown on Plate 2.6. Plate 2.6 shows the size of the interceptor throughout the alignment and also shows pipe invert and manhole elevations at key locations.

2.2.3 CSO Regulator Sites

A total of 39 CSO regulator sites were inspected by Killam personnel from May 27, 1998 through August 14, 1998. The purpose of the inspections was to determine the type of regulator and document current operating conditions of each regulator. A summary of general information relative to the inspections of the CSO regulator modules is included on Table 2.1. Descriptions of each of the regulator facilities follows.

Regulator 001

Regulator 001 is a mechanical regulator and is located in an open grass area between the north bound entrance ramps to Routes 1 and 9 just north of Dowd Avenue and east of North Avenue. A location plan of Regulator 001 is shown on Plate 2.7-1.1 which is included in Appendix B.

Combined flow enters the regulator through a 48"ϕ sewer and is regulated by a float and shuttered gate assembly. Dry weather/base flow is diverted to the 33"ϕ reinforced concrete interceptor sewer. During wet weather periods, flow rises within the facility and closes the shutter gate, which results in overflows through a 48"ϕ sewer to CSO 001 that discharges to the Peripheral ditch. A plan and section of regulator 001 is shown on Plate 2.7-1.2 included in Appendix B.

In general, the regulator facility appears to be good overall condition, however, the float and shutter mechanism appear to be frozen in the open position allowing wet weather flows to enter the interceptor sewer. The module inspection report for Regulator 001 is included in Appendix B.

City of Elizabeth - Design of Solids/Floatable Control Facilities
CSO Inspection List
Table 2.1

Regulator Modules

Number	Type	Location	Date Inspected	Discharge Point	Regulator Type	Observed Condition
001	Primary	Routes 1 & 9 Northbound Entrance Ramp	05/28/98	Peripheral Ditch	Float & Gate	1, 2
002	Primary	Division Street @ Fairmont Avenue	05/28/98	Great Ditch	Float & Gate	1,2
003-A	Relief	Westfield Avenue @ Magie Avenue	05/27/98	Elizabeth River	Weir	3,4
003-B	Relief	Grove Street & Grand Avenue	06/18/98	Elizabeth River	Weir	3,4
005	Primary	Morris Avenue & Westfield Avenue	06/18/98	Elizabeth River	See Storage Module 1	
006	Primary	Union Street @ Crane Street	06/18/98	Elizabeth River	Orifice	13,7
007	Minor	West Grand @ Union/Price & River	06/18/98	Elizabeth River	Orifice	14
008	Minor	West Grand @ Elizabeth River	08/14/98	Elizabeth River	Orifice	14
009	Minor	Elizabethtown Plaza & Caldwell	06/17/98	Elizabeth River	Weir	
010	Primary	Cherry Street & Murray Street	06/16/98	Elizabeth River	Weir	
011	Primary	Rahway Avenue & Burnet Street	06/16/98	Elizabeth River	Vortex Valve	3,7
012	Minor	Rahway Avenue & Elizabethtown Plaza	06/17/98	Elizabeth River	Vortex Valve	
013	Primary	Burnet Street Near Rahway Avenue	08/15/98	Elizabeth River	Overflow	
014	Minor	South Broad Street & Elizabeth Avenue	06/17/98	Elizabeth River	Vortex Valve	3,7
016	Minor	Pearl Street & Washington Avenue	06/17/98	Elizabeth River	Weir	
017	Minor	Broad Street @ Elizabeth River	06/18/98	Elizabeth River	Weir	
021	Relief	Third Avenue between S. Spring & S. Reid Streets	05/28/98	Elizabeth River	Overflow	7
022	Primary	South Street , South Spring St. & 4th St.	06/16/98	Elizabeth River	Weir	
024	Minor	Norwood Terrace @ S. Pearl Street	06/18/98	Elizabeth River	n/a	12
025	Minor	S. Pearl Street & Montgomery Street	06/17/98	Elizabeth River	Overflow	15, 16
026	Primary	John Street (dead end) @ Elizabeth River	05/27/98	Elizabeth River	Float & Gate / Weir	1, 7
027	Primary	Summer Street & Clarkson Avenue	06/17/98	Elizabeth River	See Storage Module 7	
028	Relief	Summer Street & Clarkson Avenue	06/17/98	Elizabeth River	See Storage Module 7	
029	Primary	S. First Street @ Elizabeth Avenue (Waterfront Park)	05/27/98	Elizabeth River	Float & Gate	1
030	Relief	S. Front Street @ E. Jersey Street	06/01/98	Arthur Kill	Overflow	9
031	Primary	Livingston Street @ Front Street	06/01/98	Arthur Kill	Float & Gate	1
032	Primary	Front Street @ Magnolia Avenue	06/01/98	Arthur Kill	Float & Gate	1, 2
034-A	Primary	Atlanta Plaza (in parking lot)	05/29/98	Newark Bay	Float & Gate	5, 7, 10
034-B	Primary	Trumbull Street @ First Street	06/02/98	Newark Bay	Float & Gate	7
035	Primary	S. First Street @ Third Avenue	05/28/98	Elizabeth River	Float & Gate	1, 7, 8
036	Relief	intersections of N. Broad Street, Salem Avenue & Pingry Place	06/02/98	Elizabeth River	Overflow	
037	Primary	Bayway @ former S. Front Street (private road)	05/29/98	Arthur Kill	Float & Gate	1, 3
038	Relief	Third Avenue @ Atlantic Street (under NJ TPK. overpass)	06/01/98	Elizabeth River	Weir	11
039	Relief	Trumball Street @ Fourth Street	06/02/98	Great Ditch	Overflow	
040	Primary	Clifton Street @ Pulaski Street	05/28/98	Elizabeth River	Float & Gate / Weir	1, 3, 5, 6
041	Relief	Morris Avenue at Elizabeth River	06/18/98	Elizabeth River	See Storage Module 1A	
042A	Relief	Elizabeth Avenue & Bridge Street	06/17/98	Elizabeth River	Weir	3
042B	Relief	East Jersey Street & Winfield Scott Plaza	06/17/98	Elizabeth River	Weir	
042C	Relief	Jefferson Avenue & Chestnut Street	06/17/98	Elizabeth River	Weir	

** To be inspected by Killam. On 6/18/98 we could not inspect due to emergency repairs being performed to repair a collapsed main.

*** To be inspected by Killam.

Description of Observed Conditions

1 Float and gate mechanism appear to be "frozen" in the open position, allowing wet weather flows to enter the interceptor sewer.
2 Manhole frame(s) shifted from original position (not aligned with opening in chamber top slab)
3 No manhole steps in chamber.
4 Interior of chamber has been coated with gunite.
5 Grease accumulated on interior of chamber.
6 Manhole frame(s) cracked.
7 Sediment and debris accumulated on bottom of chamber.
8 Emergency overflow to the Great Ditch.
9 Outfall 030 was reportedly plugged and demolished at one time, then reconstructed with a tide gate and headwall in the marina along Waterfront Park.
10 Evidence of surcharging observed.
11 Weir damaged/partially eroded
12 The regulator is blocked. Flow goes directly into the interceptor.
13 Eighteen inch void in manhole base. It has been reported that the outfall line is collapsed.
14 Overflow pipe has a sluice gate which was observed open.
15 Tide gate is "frozen" in the open position.
16 Excessive infiltration was observed coming thru the tide gate.

The results of the inspection indicated that the facility was in fairly good overall condition. The 15"ϕ sewer to the interceptor was being constructed during the June 18, 1998 inspection. The module inspection report for Regulator 017 is included in Appendix B.

Regulator 021

Regulator 021 is a non-mechanical regulator located in Third Avenue near South Reed Street. A location plan and a plan and section of Regulator 021 are shown on Plates 2.7-21.1 and 2.7-21.2 respectively and are included in Appendix B.

Dry weather/base flow enters the manhole chamber through a 12"ϕ combined sewers and discharges to the interceptor through a 12"ϕ sewer. When wet weather flow surcharges the manhole the flow is diverted through a 15"ϕ overflow sewer to CSO 021, which discharges to the Elizabeth River.

Regulator 021 was observed be in good condition. The module inspection report for Regulator 021 is included in Appendix B.

Regulator 022

Regulator 022 is a non-mechanical regulator located at the intersection of South Street and South Spring Street. A location plan and a plan and section of Regulator 022 are shown on Plates 2.7-22.1 and 2.7-22.2 respectively and are included in Appendix B.

During dry weather/base flow conditions, flow enters the manhole structure through a 48"W x 72"H combined brick sewer and the flow exits the manhole through a 15"ϕ sewer which conveys wastewater to the interceptor sewer. During wet weather flow conditions, the manhole surcharges and the flow discharges over a weir through a 48"W x 72"H brick sewer that conveys overflow to CSO 021, which discharges to the Elizabeth River.

The results of the inspection indicated that the facility was in fairly good overall condition. The module inspection report for Regulator 021 is included in Appendix B.

Regulator 024

Regulator 024 is located at the intersection of Pearl Street and Norwood Terrace. A location plan for Regulator 024 is shown on Plate 2.7-24.1 and is included in Appendix B. As part of the field observations, it was determined that the regulator has been filled with dirt and this outfall has been abandoned and flows go directly to the adjacent westerly interceptor.

Regulator 025

Regulator 025 is a non-mechanical regulator located at the intersection of South Pearl Street and Montgomery Street. A location plan and a plan and section of Regulator 025 are shown on Plates 2.7-25.1 and 2.7-25.2 respectively and are included in Appendix B.

During dry weather/base flow conditions, flow enters the manhole structure through a 12"ϕ combined sewer and the flow exits the manhole through a 12"ϕ sewer which conveys wastewater to the interceptor sewer. During wet weather flow conditions, the manhole surcharges and the flow discharges through a 12"ϕ line which conveys overflow through a tide gate to CSO 025, which discharges to the Elizabeth River.

The results of the inspection indicated that the facility was in good overall condition with the interior recently gunited. The tide gate was observed to be rusted in the open position allowing excessive infiltration during high tide. The module inspection report for Regulator 025 is included in Appendix B.

to the Arthur Kill. A plan and section of Regulator 034B is shown on Plate 2.7-34.4 which is included in Appendix B.

The regulator facility appears to be good overall condition, however, the float and shutter mechanism appear to be frozen in the open position allowing wet weather flows to enter the interceptor sewer. The module inspection report for Regulator 034B is included in Appendix B

Regulator 035

Regulator 035 is a mechanical type regulator located adjacent to South First Street and across from Third Avenue. A plan showing the general location of Regulator 035 is shown on Plate 2.7-35.1 and is included in Appendix B.

Combined flow enters the regulator through a 41"ϕ gunited brick sewer and is regulated by a float and shutter gate assembly. Dry weather/base flow is diverted through a 15"ϕ sewer to the interceptor sewer. During wet weather periods, flow rises within the facility and closes the shutter gate, resulting in overflows through a 54"ϕ sewer to CSO 035 which discharges to the Elizabeth River. An emergency overflow weir chamber is located downstream along the outfall line, between the regulator module and the sluice gate chamber. A plan and section of Regulator 035 is shown on Plate 2.7-35.2 which is included in Appendix B.

The regulator facility appears to be good overall condition, however, the float and shutter mechanism appear to be frozen in the open position allowing wet weather flows to enter the interceptor sewer. The module inspection report for Regulator 035 is included in Appendix B.

Regulator 036

Regulator 036 is a non-mechanical regulator located within a manhole structure at the intersection of North Broad Street and Salem Avenue. A plan showing the general location of Regulator 036 is shown on Plate 2.6-36.1 and is included in Appendix B.

A weir diverts normal wastewater flows from 54"ϕ combined sewer, to the 15"ϕ sewer which is tributary to the interceptor. A float controlled regulator gate downstream of the 15"ϕ sewer limits the wet weather flow from passing to the interceptor sewer. During wet weather conditions, the regulator surcharges and flow passes through a 48"ϕ outflow sewer to CSO 040 which discharges to the Elizabeth River.

In general, the regulator module structure appears to be in relatively good condition. The operating mechanisms for the float and shutter gate appear to be not functioning allowing wet weather flows to enter the interceptor sewer. The module inspection report for Regulator 040 is included in Appendix B.

Regulator 041

Regulator 041 is located on Morris Avenue adjacent to Sayre Street and immediately upstream of the siphon which crosses the Elizabeth River. As part of the work under Contract No. 21, Regulator 41 was consolidated into Storage Module 1A. A general location plan and a plan and section of Regulator 041 are shown on Plates 2.7-41.1 and 2.7-41.2 respectively and are included in Appendix B. A detailed discussions of Regulator 41 / Storage Module 1A is included in Section 2.2.4.

Regulators 042A, 042B & 042C

CSO 042 has three separate non-mechanical regulators designated as 042A, 042B and 042C. The three regulators have of weir walls which divert dry weather/base flows to the interceptor sewers. Wet weather flows surcharge the regulator and flow to CSO 042.

Regulator 042A is located at the Elizabeth Avenue and Bridge Street intersection. A location plan and a plan and section of Regulator 042A are shown on Plates 2.7-42.1 and 2.7-42.2 respectively

continued

and are included in Appendix B. The module inspection report for Regulator 042A is included in Appendix B.

Regulator 042B is located adjacent to City Hall at the intersection of East Jersey Street and Winfield Scott Plaza. A location plan and a plan and section of Regulator 042B are shown on Plates 2.7-42.3 and 2.7-42.4 respectively and are included in Appendix B. The module inspection report for Regulator 042B is included in Appendix B.

Regulator 042C is an L shaped concrete chamber located at the intersection of Jefferson Avenue and Chestnut Street. A location plan and a plan and section of Regulator 042C are shown on Plates 2.7-42.5 and 2.7-42.6 respectively and are included in Appendix B. The module inspection report for Regulator 042C is included in Appendix B.

2.2.4 In-line Storage Facilities

The combine sewer system of the City of Elizabeth has twelve (12) in-line storage facilities which were constructed under Contract No. 21 in 1990. The intended purpose of the storage modules is to store wet weather flow until the flow can be received at the treatment facility and for the retention of "first flush" storm water flows for dilution and ultimate discharge to the overflow waterway. The storage modules were inspected by Killam personnel from June 3, 1998 through June 18, 1998. The purpose of the inspections was to determine the current operating condition of each of the storage modules. A summary of general information relative to the inspections of the storage modules is included on Table 2.2. Descriptions of each facility is as follows:

Storage Module 001

Storage Module 001 is located within a cartway of Westfield Avenue just west of Morris Avenue and is the converted site of Regulator 005. A general location plan of Storage Module 001 is shown on Plate 2.8-1.1 and is included in Appendix C.

The storage module is a rectangular concrete chamber which has been constructed in-line with the existing combined sewer. Dry weather flows are diverted from the 72"ϕ concrete influent line through a 24"ϕ outlet which discharges to the interceptor sewer. Under storm events, the flap gate would open, thereby permitting storm related wastewater flows to the 78"ϕ concrete overflow piping. A general plan and section of Storage Module 001 is shown on Plate 2.8-2.2 and is included in Appendix C. A summary report of the inspection undertaken is also included in Appendix C.

Storage Module 001A

Storage Module 001A is also located in Morris Avenue adjacent to the Elizabeth River. This storage module was converted from Regulator 041 as part of work included under Contract No. 21. A general location plan of Storage Module 001A is shown on Plate 2.8-1.3 and is included in Appendix C.

Storage Module 001 is located upstream of the Elizabeth River and is significantly different than the other storage modules since it includes a siphon inlet chamber. Under normal dry weather flows, wastewater enters the facility through the 72"ϕ influent sewer and is discharged into two-14"ϕ and one-8"ϕ cast iron siphon pipes which pass under the Elizabeth River. Under normal conditions, a flap valve within the upper portion of the chamber is closed thereby preventing wastewater flow through the upper portion of the chamber into the 66"ϕ outlet sewer which discharges through CSO 041 and into the Elizabeth River. Under wet weather flow conditions, the flap valve will open and flow will be discharged to CSO 041. A general plan and section of Storage Module 001A is shown on Plate 2.8-1.4 and is included in Appendix C. An inspection report for Storage Module 001A is also included in Appendix C.

Storage Module 002

Storage Module 002 is located within an easement area of a residential lot along the Elizabeth River in a parking area behind apartment house #18-20 Sayre Street. A plan showing the general

City of Elizabeth - Design of Solids/Floatable Control Facilities
Storage Module Inspection Summary
Table 2.2

Storage Modules

Module Number	Location	Observed Flap Gate Position	Observed Condition	Date Inspected	Discharge Point
S-1	Westfield Avenue @ Morris Avenue	Closed		06/18/98	Elizabeth River
S-1A	351 Morris Avenue	Closed		06/18/98	Elizabeth River
S-2	20 Sayre Street @ Elizabeth River (easement)	Closed	1, 2	06/03/98	Elizabeth River
S-3	Westfield Avenue @ Elizabeth River (easement)	Closed **	3, 4, 5	06/03/98	Elizabeth River
S-4	Dod Court @ Elizabeth River (easement)	Closed	1	06/03/98	Elizabeth River
S-5	Bridge Street @ Elizabeth River (easement)	Closed	6	06/03/98	Elizabeth River
S-7	Summer Street @ Clarkson Avenue	1/2 Open		06/17/98	Elizabeth River
S-8	927 Van Buren Avenue (near Alina Street)	Open	7	06/04/98	Peripheral Ditch
S-10	Alina Street @ Madison Avenue	Closed		06/18/98	Peripheral Ditch
S-11	Alina Street @ Jackson Avenue	Closed	8	06/04/98	Peripheral Ditch
S-12	Island @ intersection of Dowd Avenue & North Avenue East	2/3 Open	9	06/03/98	Great Ditch
S-13	Broadway @ Front Street	Closed	10	06/04/98	Arthur Kill
S-14	Third Avenue @ South First Street	Open	11,12	06/16/98	Elizabeth River

Note - As per previous reports, storage modules 6 & 9 do not exist.

** The flap gate in S-3 was found in the open position when inspection was started. DPW personnel closed the flap gate in the manual hand mode upon completing the inspection.

Description of Observed Conditions

1 Unit reportedly working properly according to DPW personnel.
2 Sediment accumulated on bottom of chamber.
3 Sanitary flows are pumped out of chamber.
4 Original concrete top slab has been removed and replaced with new slab which is not square to the chamber walls.
5 Only one out of four stainless steel screens are in place at stilling well.
6 Infiltration greater than approximately five gallons per minute observed in chamber.
7 Only one diversion manhole installed outside of chamber containing hydrobrake.
8 Dry (control) chamber is flooded and could not be inspected, reportedly from electric service to unit being terminated.
9 Main sewer line filled with approximately three feet of standing water.
10 Dry (control) chamber is flooded with over eleven feet of water and could not be inspected.
11 Dry (control) chamber is flooded with over ten feet of water and could not be inspected.
12 Did not access the chamber because Air Monitor Alarm. (O2 = 19.2 / LEL = 103 / HS = 2ppm)

continued

Storage Module 013

Storage Module 013 is located along Broadway at the intersection of Front Street. A location plan for Storage Module 013 is shown on Plate 2.8-13.1 and is included in Appendix C.

Storage Module 013 is an in-line storage facility which was constructed in-line to the 60" combined sewer. Dry weather flows are routed by gravity through a 12"ϕ diversion pipe to the adjacent interceptor sewer. Under wet weather flow conditions, combined flow is routed through the chamber to the downstream 60" sewer which discharges to the Arthur Kill. A plan and section of Regulator 013 is shown on Plate 2.8-13.2 and is include in Appendix C. A brief summary report of the inspection of Storage Module 013 is also included in Appendix C.

Storage Module 014

Storage Module 014 is located within Third Avenue just north of South First Street. A location plan for Storage Module 014 is shown on Plate 2.8-14.1 and is included in Appendix C.

Storage Module 014 is constructed in-line to the existing 44" gunited brick sewer and is similar to Storage Module 008 and 010 with a gravity diversion around the flap gate assembly to control dry weather flows to the downstream sewer. Under wet weather conditions, flow will pass through the storage module to the downstream sewer which is tributary to Regulator 035. A plan and section of Storage Module 014 is shown on Plate 2.8-14.2 and is included in Appendix C. A summary report of the inspection undertaken for Storage Module 014 is also included in Appendix C.

2.2.5 Flushing Facilities

As noted earlier, the intended purpose of the flushing modules is to limit pollution discharge to the c ow waterway. This is accomplished by reducing the impact of the first flush by periodically

continued

showing the extent of the work required to separate the storm and sanitary sewers is shown on Plate 4.2-17.

CSO 021

CSO 021 is located at the Elizabeth River near Route 1 within the City of Elizabeth DPW Yard. With a design capacity of 11 MGD, CSO 021 is a good candidate for static screening facilities. The concept of sewer separation is not viable at this location. A review of the various alternatives which may be implemented at this location indicates that static screening is the most cost effective option. A summary of the cost of the various alternatives is included in Appendix G. The estimated costs for construction of a static screening facility at the interceptor discharge to the outfall and present worth O & M costs are approximately $154,400. A plan showing the recommendation location for the screening facility is shown on Plate 4.2-21.

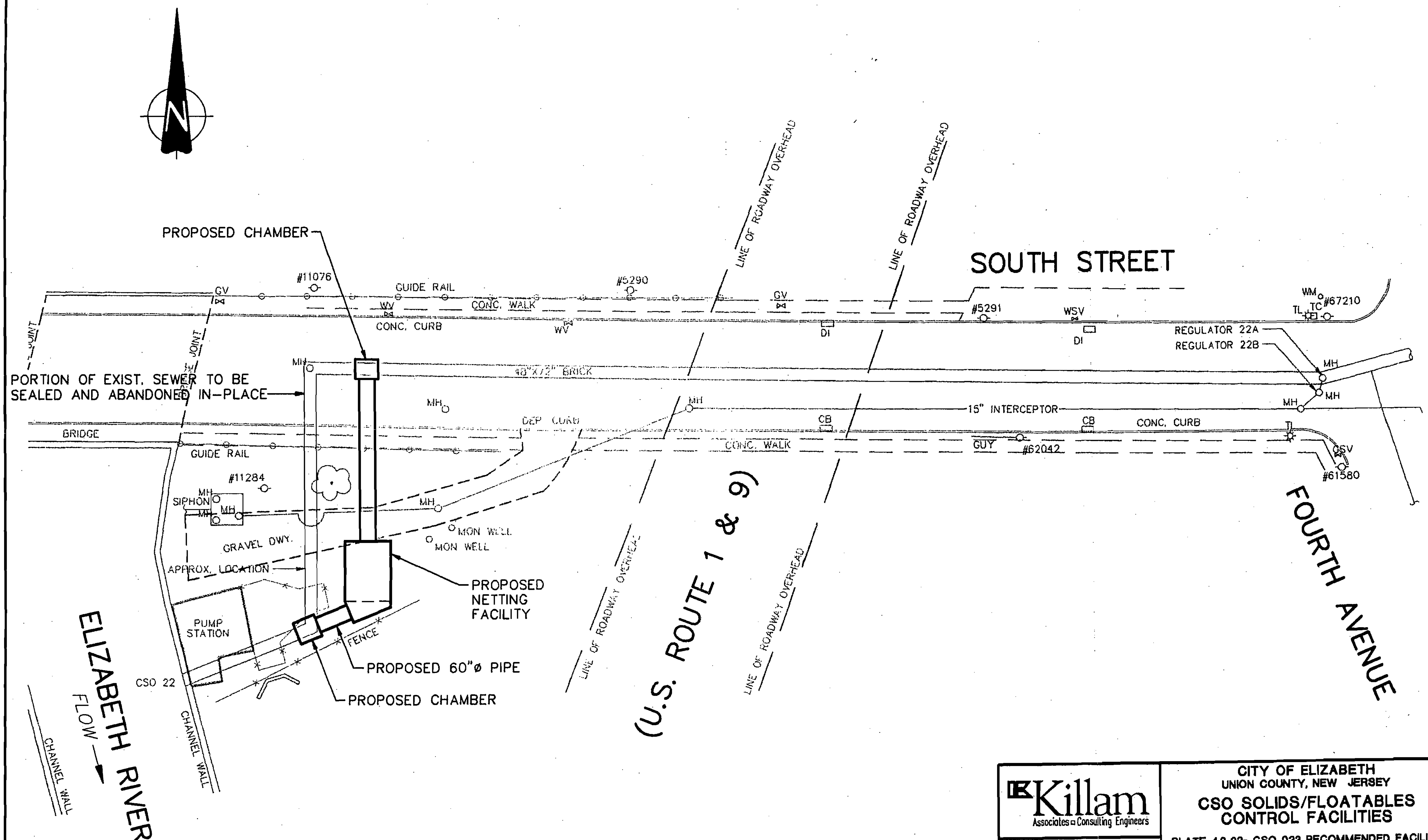
CSO 022

CSO 022 has a design capacity of 75 MGD and is located adjacent to South Street and the Elizabeth River in the vicinity of Routes 1 and 9. Due to the high flow rate, the concept of a static screen is not viable nor is sewer separation. A summary of the cost for netting is included in Appendix G.

Based upon the evaluations undertaken, the most cost effective option for providing solids/floatable control at CSO 022 is an inline netting facility. The estimated construction and present worth O&M cost for the netting facility would be approximately $855,100. A plan showing the recommended location and configuration of the netting facility is shown on Plate 4.2-22.

CSO 025

CSO 025 discharges to the Elizabeth River adjacent to South Pearl Street and Montgomery Street. The concept of sewer separation at this location was reviewed and determined to be a viable



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27 Bleeker Street
Millburn, New Jersey 07041

CITY OF ELIZABETH
UNION COUNTY, NEW JERSEY
CSO SOLIDS/FLOATABLES CONTROL FACILITIES

PLATE 4.2-22- CSO 022 RECOMMENDED FACILITY

Designed	Drawn	Checked	Approved	Date	Scale
J.A.F.	J.A.F.	M.A.T.			1"=30'

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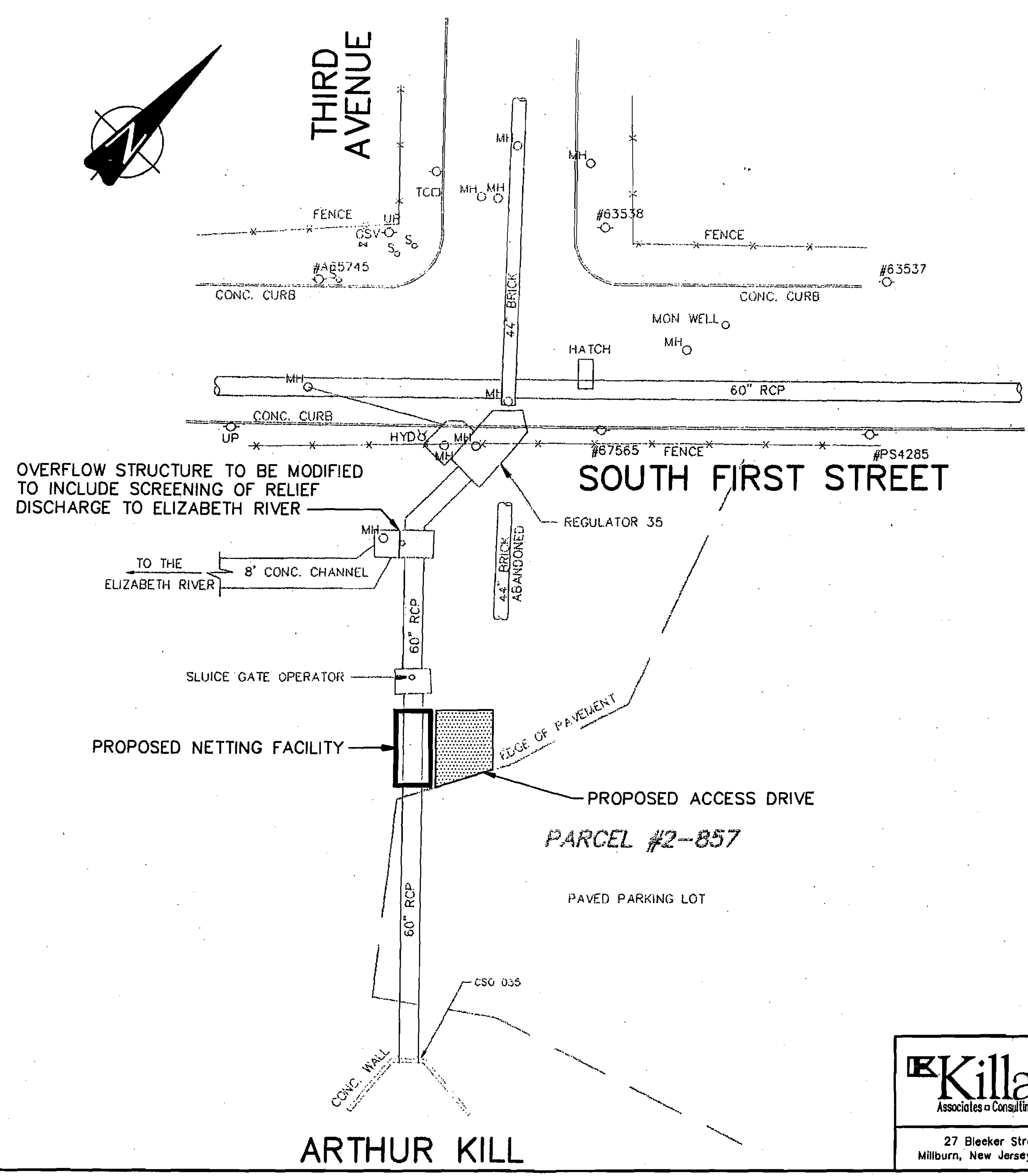
A summary of the estimated costs for the netting alternative is included in Appendix G. The analysis showed that inline netting was the most cost effective option with a total construction and present worth O&M cost of $1,120,100. A plan showing the location and configuration of the recommended inline netting facility is shown on Plate 4.2-34. The City must evaluate the extend of existing easements in order to determine whether or not additional easements on Parcel #1-120 would be required for the recommended facilities.

CSO 035

CSO 035 discharges to the Arthur Kill southeast of the intersection of Third Avenue and South First Street. Flow is regulated through the regulator immediately adjacent to the street intersection and is discharged through a 60" overflow to the Arthur Kill. The design flow of CSO 035 is 100 MGD. The cost estimate for netting facilities for CSO 035 is included in Appendix G. The netting and mechanical screening alternatives were reviewed in order to determine the most cost effective option. The estimated construction and present worth O&M cost of the netting facility is $1,100,100. A plan showing the recommended configuration and location of the inline netting facility is shown on Plate 4.2-35. It would be necessary to evaluate the extend of existing easements on Parcel #2-857. It would also be necessary to determine the extent of available access to the proposed netting facility in order to determine whether additional easements and access for future maintenance may be required.

CSO 036

Regulator 036 is located near the intersection of Pingry Place, North Broad Street and Salem Avenue. The regulator discharges flows from the 45" X 67.5" brick sewer through a 42" relief sewer and ultimately to a 90" relief sewer. The design flow for CSO 036 is 115 MGD. A cost summary of the netting facility for CSO 036 is included in Appendix G. The netting facilities are estimated to have a total construction and present worth O&M cost of $1,100,100.



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CITY OF ELIZABETH
UNION COUNTY, NEW JERSEY
CSO SOLIDS/FLOATABLES CONTROL FACILITIES

PLATE 4.2-35 - CSO 035 RECOMMENDED FACILITY

Designed	Drawn	Checked	Approved	Date	Scale
J.A.F.	J.A.F.	M.A.T.			1"=30'

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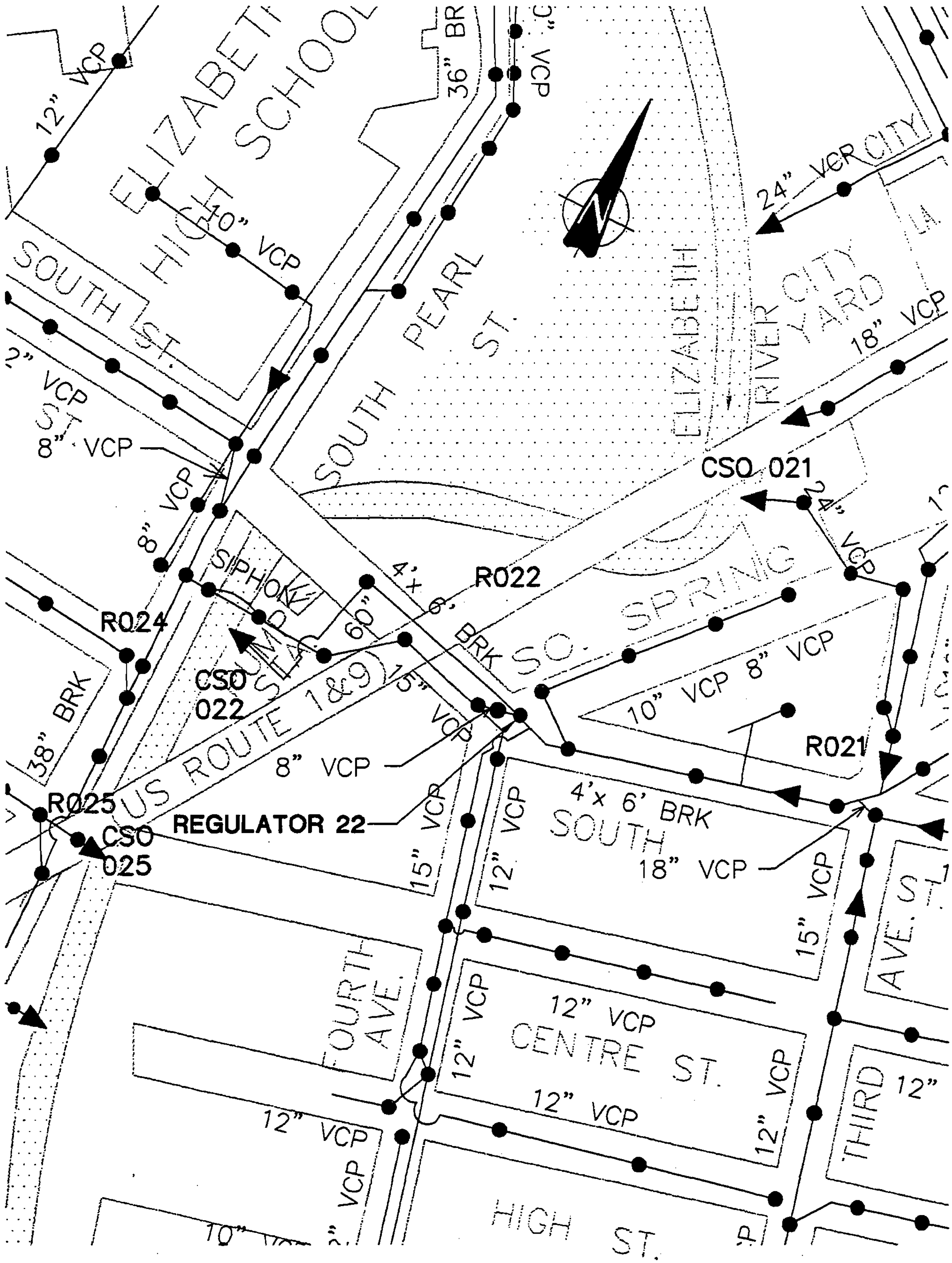
CITY OF ELIZABETH
CSO Solids/Floatables Control Facilities

<u>Module Inspection Report</u>

Module Number	R-022
CSO Number	Primary CSO 022 - Discharges to the Elizabeth River Flume
Module Type	Regulator - Non-Mechanical (Weir)
Inspection Date	August 15, 1998
Location	In South Street near Fourth Avenue and South Spring Street
Description	The weir is located in a brick manhole chamber on the 4' x 6' brick combined sewer line. Dry weather flow is intercepted from this manhole through a 15" tile pipe to a manhole to the southwest. Wet weather flow overtops a weir into a 4' x 6' brick outfall.
Connections	48"W x 72"H brick combined sewer influent line 15"ø tile effluent interceptor line 48"W x 72"H brick outfall effluent
Chambers (internal dimensions)	Weir chamber- R022 circular brick w/ 36"ø MH
Observations	The interior of the structure was observed to be in fairly good overall condition. No manhole steps were observed.



LEGEND:

S001 – STORAGE MODULE
F001 – FLUSHING MODULE
R001 – REGULATOR MODULE
CSO 001 – COMBINED SEWER OVERFLOW

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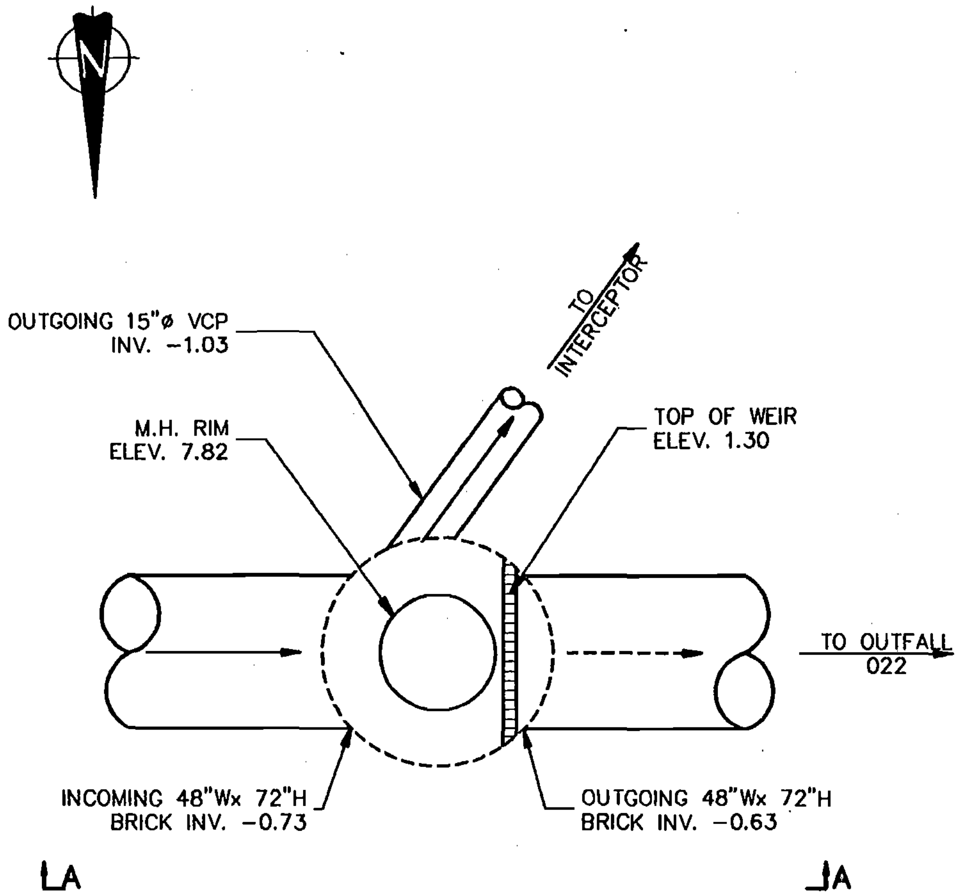
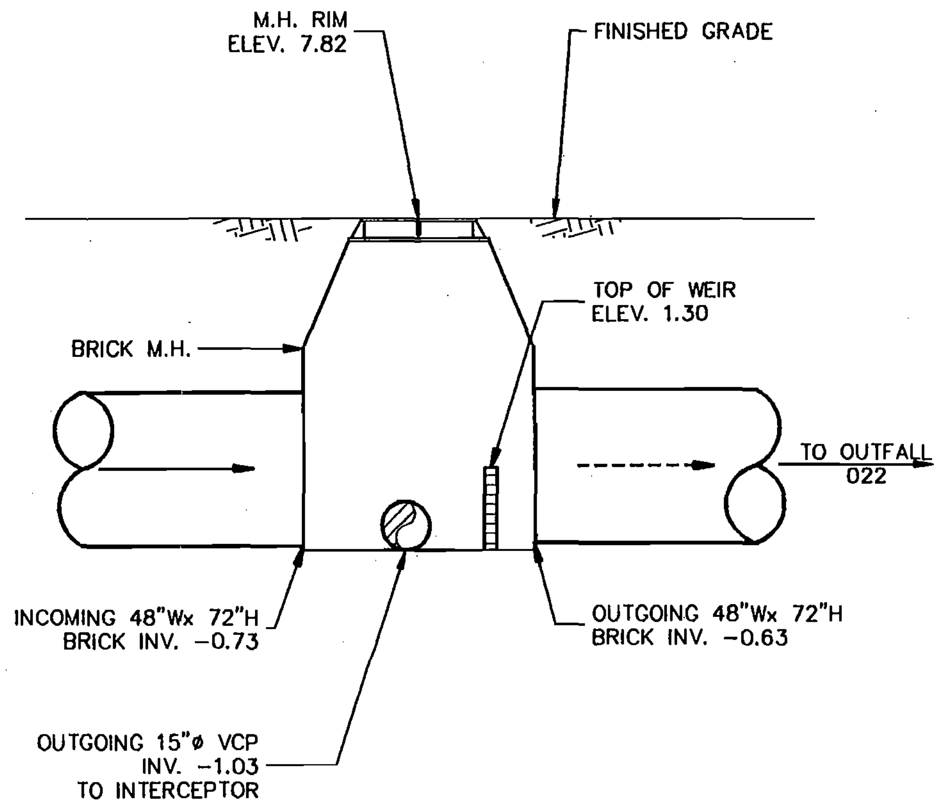
Associates ▫ Consulting Engineers
27 Bleeker Street

CITY OF ELIZABETH
UNION COUNTY, NEW JERSEY
CSO SOLIDS/FLOATABLES CONTROL FACILITIES
PLATE 2.7-22.1 - REGULATOR 022 LOCATION PLAN



SECTIONAL PLAN
NOT TO SCALE



SECTION A–A
NOT TO SCALE

LEGEND

——→ DRY WEATHER FLOW
- - - - → WET WEATHER FLOW

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CITY OF ELIZABETH
UNION COUNTY, NEW JERSEY

CSO SOLIDS/FLOATABLES
CONTROL FACILITIES

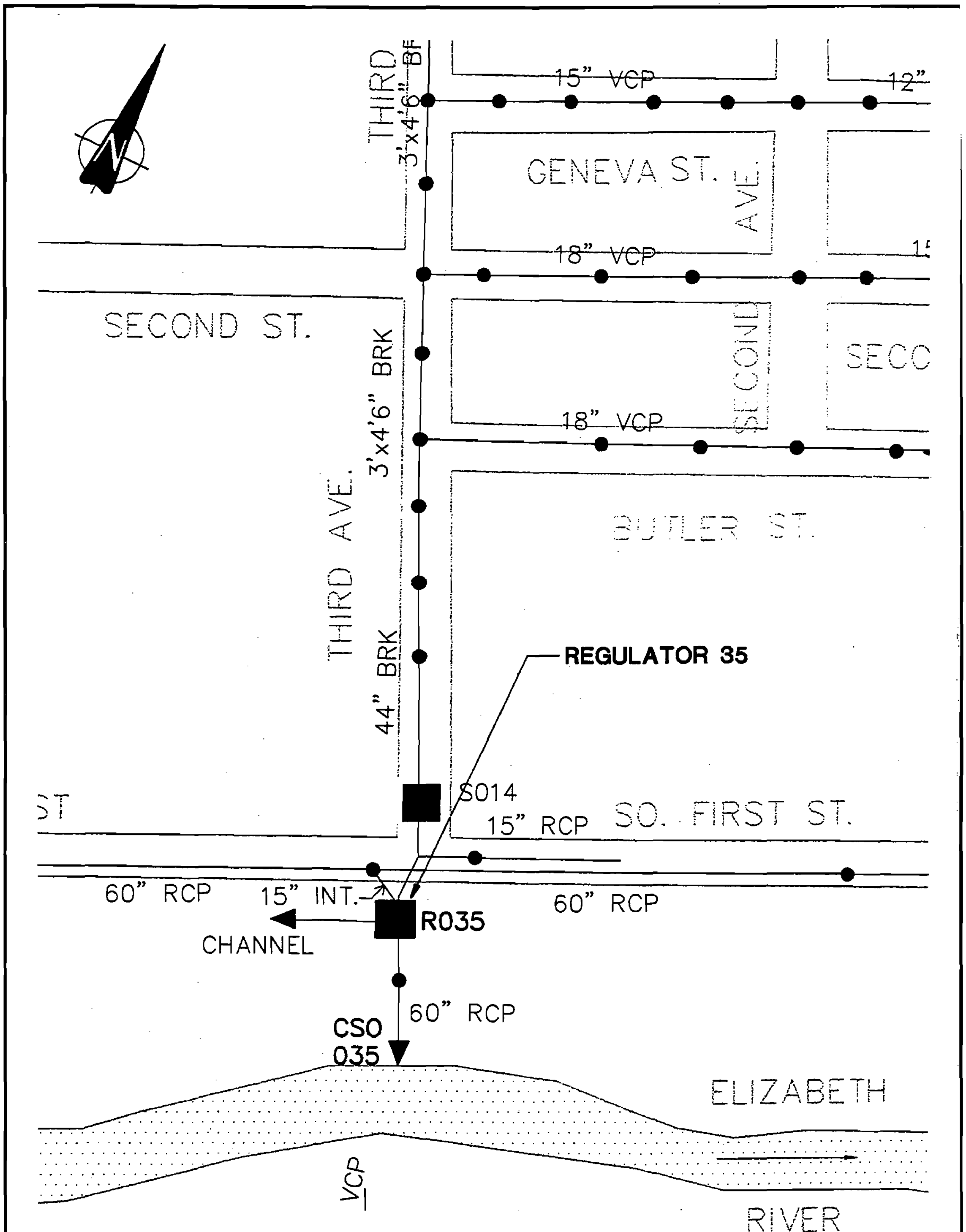
PLATE 2.7-22.2 REGULATOR 022 SCHEMATIC

Designed	Drawn	Checked	Approved	Date	Scale
J.J.M.	J.J.M.	J.A.F.			N.T.S.

CITY OF ELIZABETH
CSO Solids/Floatables Control Facilities

Module Inspection Report

Module Number	R-035
CSO Number	Primary CSO 035 - Discharges to the Elizabeth River
Module Type	Regulator - Mechanical (Float & Regulator Gate)
Inspection Date	May 28, 1998
Location	On the side of South First Avenue across from Third Avenue
Description	The module is an "L" shaped subsurface concrete chamber with approximate overall dimensions of 22' x 19'. Dry weather flows pass from the diversion chamber to the regulator chamber through a tapered concrete channel. In the regulator chamber a float controlled shutter gate is intended to prevent wet weather flows from passing to the interceptor. During wet weather flow periods, the flow level must rise above the diversion berm to pass through the outfall pipe. An emergency overflow weir chamber is located downstream along the outfall line, between the regulator module and the sluice gate chamber.
Connections	41"ø gunited brick influent line 15"ø reinforced concrete interceptor line 54"ø gunited reinforced concrete outfall line
Chambers **(internal dimensions)**	Diversion chamber - R035-1 (7'-9" x 8'-6") w/ 24"ø MH Regulator chamber - R035-2 (6' x 11'-1") w/ 30"ø MH Emergency overflow weir chamber - R035-3A (7'-7" x 5') w/ 32"ø MH Sluice gate chamber - R035-3B (7'-1" x 4') w/ iron vault doors
Observations	Approximately 16" of sediment & grease was observed in the diversion and regulator chambers. The float and shutter gate mechanism are in poor condition and appear to be frozen in the open position, allowing wet weather flows to enter the interceptor sewer. The emergency overflow weir chamber and sluice gate chamber were observed to be in excellent condition.



LEGEND:

S001 – STORAGE MODULE
F001 – FLUSHING MODULE
R001 – REGULATOR MODULE
CSO 001 – COMBINED SEWER OVERFLOW

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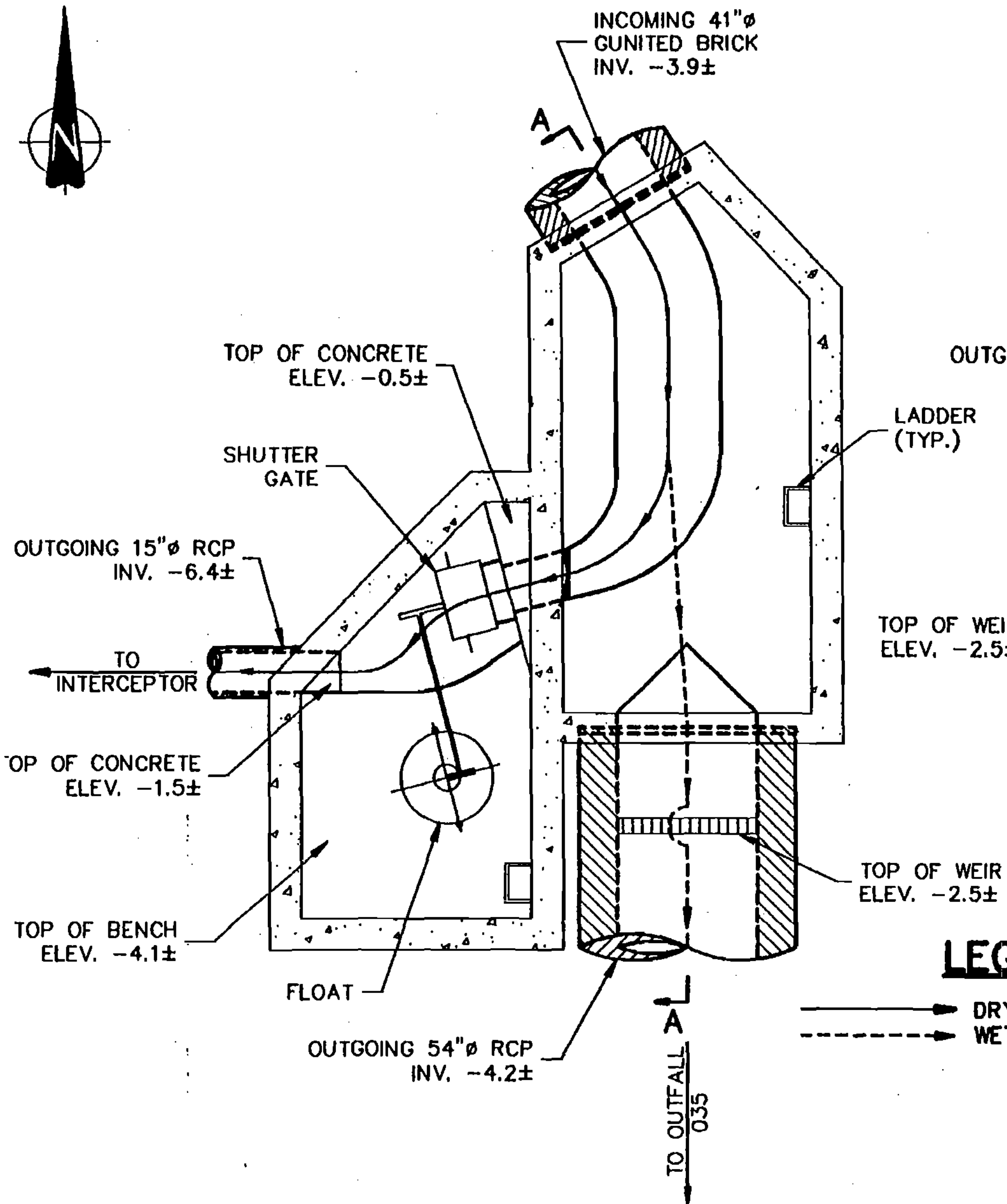
CITY OF ELIZABETH
UNION COUNTY, NEW JERSEY

CSO SOLIDS/FLOATABLES CONTROL FACILITIES

PLATE 2.7-35.1 - REGULATOR 035 LOCATION PLAN

Designed	Drawn	Checked	Approved	Date	Scale



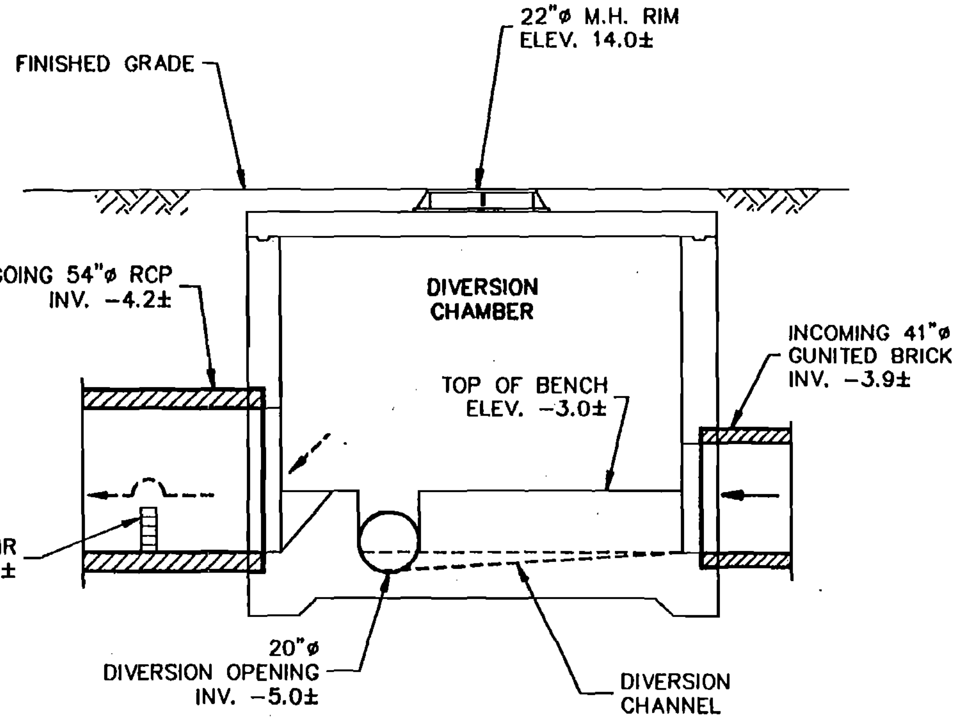
SECTIONAL PLAN

NOT TO SCALE

LEGEND

DRY WEATHER FLOW

WET WEATHER FLOW



SECTION A-A

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UNION COUNTY, NEW JERSEY

CSO SOLIDS/FLOATABLES
CONTROL FACILITITES

PLATE 2.7-35.2 REGULATOR 035 SCHEMATIC

Designed	Drawn	Checked	Approved	Date	Scale

CITY OF ELIZABETH
CSO Solids/Floatables Control Facilities

Module Inspection Report

Module Number	S-014
Module Type	Storage (in-line, returned gravity diversion)
Inspection Date	June 16, 1998
Location	Within the cartway of Third Avenue just north of South First Street. The control cabinets are located within the western sidewalk area of Third Avenue.
Description	The module is a rectangular concrete chamber with approximate overall exterior dimensions of 19' x 18' with a 44" x 112" flap gate which has been constructed in-line with the existing combined sewer line. The module receives combined flows from Flushing Module No. 12, which is located to the north along Third Avenue near Florida Street. Dry weather flows are routed from the influent line through a concrete diversion channel which is then piped through the equipment chamber in a cast/ductile iron pipe. A knife gate within the equipment chamber isolates flow to the diversion line. Flow through the diversion line is controlled by a hydrobrake/vortex valve located in a manhole adjacent to the module. From the diversion manhole, the flow is returned to the module downstream of the flap gate. Large storm flows are passed through the module to the downstream combined sewer. A regulator just outside the cartway of South First Street at Third Avenue diverts flows to either the Easterly Interceptor or the Elizabeth River.
Connections	± 44"ø brick influent line (gunited) 18"ø iron diversion line ± 44"ø brick effluent line (gunited)
Chambers **(internal dimensions)**	Diversion chamber - S014-1 (7' x 8'-8") w/ 42"ø MH Flap gate chamber - S014-2 (10'-4" x 8'-8") w/ 30"ø MH Equipment chamber - S014-3 (17'-4" x 6') w/ 42"ø MH

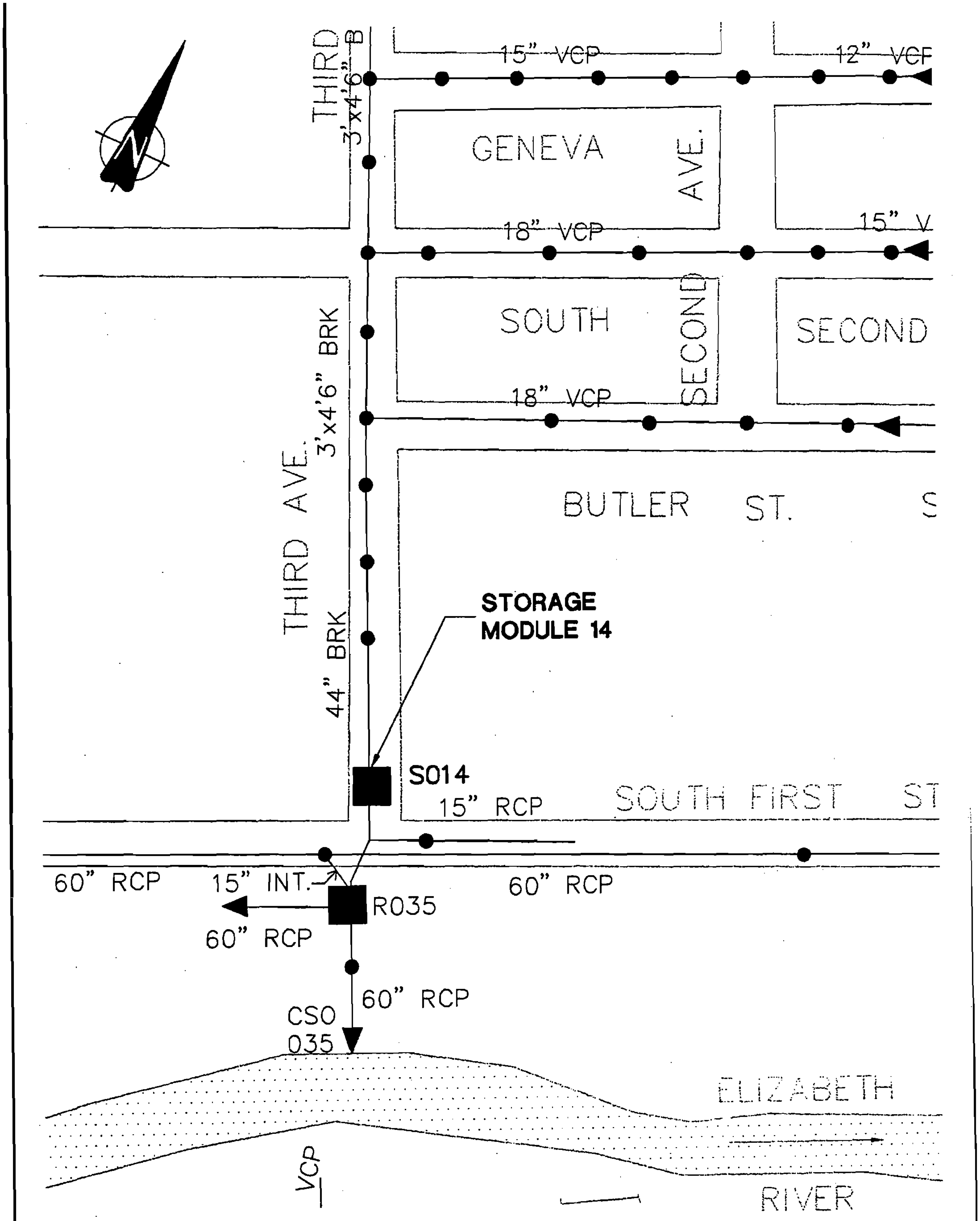
CITY OF ELIZABETH
CSO Solids/Floatables Control Facilities

Module Inspection Report

Module Number S-014

Observations

The module structure and flap gate components appear to be in good overall condition, given the limited inspection performed. A limited inspection of the module was performed as the air monitor alarm sounded. The monitor indicated a Lower Explosive Level (LEL) of 103% and an Oxygen (O_2) level of 19.2%. Explosives must be less than 10% LEL and O_2 must be between 19.5% and 23.5% for entry. It should be noted that the module is adjacent to a chemical company and was the only inspection location where the air monitor alarm sounded. The equipment chamber was observed to be filled with 10' of water and the chamber ladder was damaged. Based on the sustained submergence in water, it is questionable if any of the equipment would be operable if the chamber was dewatered. At the time of inspection, the flap gate was in the open position, thus the non-functioning unit would not have any negative impact on the system, other than not storing wet wether flows in the upstream line and diverting dry weather flows as originally designed. The depth of flow through the flap gate chamber was over 2' at the time of inspection and evidence of surcharging to the top of the chamber was observed. The control cabinets where reportedly damaged by tractor trailers making right turns from South First Street onto Third Avenue. As with all of the storage modules, the unit reportedly does not communicate with the Trenton Avenue Pump Station as originally designed.



LEGEND:

S001 – STORAGE MODULE
F001 – FLUSHING MODULE
R001 – REGULATOR MODULE
CSO 001 – COMBINED SEWER OVERFLOW

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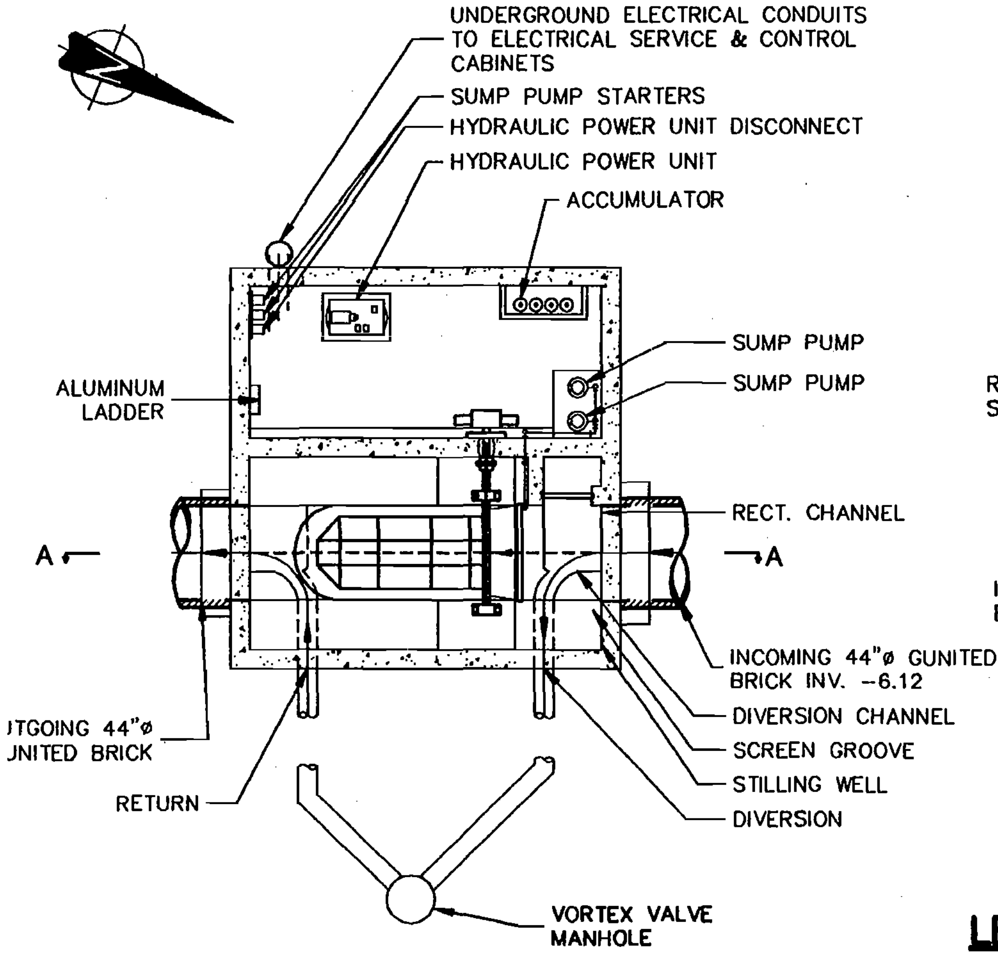
CITY OF ELIZABETH
UNION COUNTY, NEW JERSEY

CSO SOLIDS/FLOATABLES CONTROL FACILITIES

PLATE 2.8-14.1 STORAGE MODULE 14 LOCATION PLAN

Designed	Drawn	Checked	Approved	Date	Scale
J.J.M.	J.J.M.	J.A.F.			1"=200'

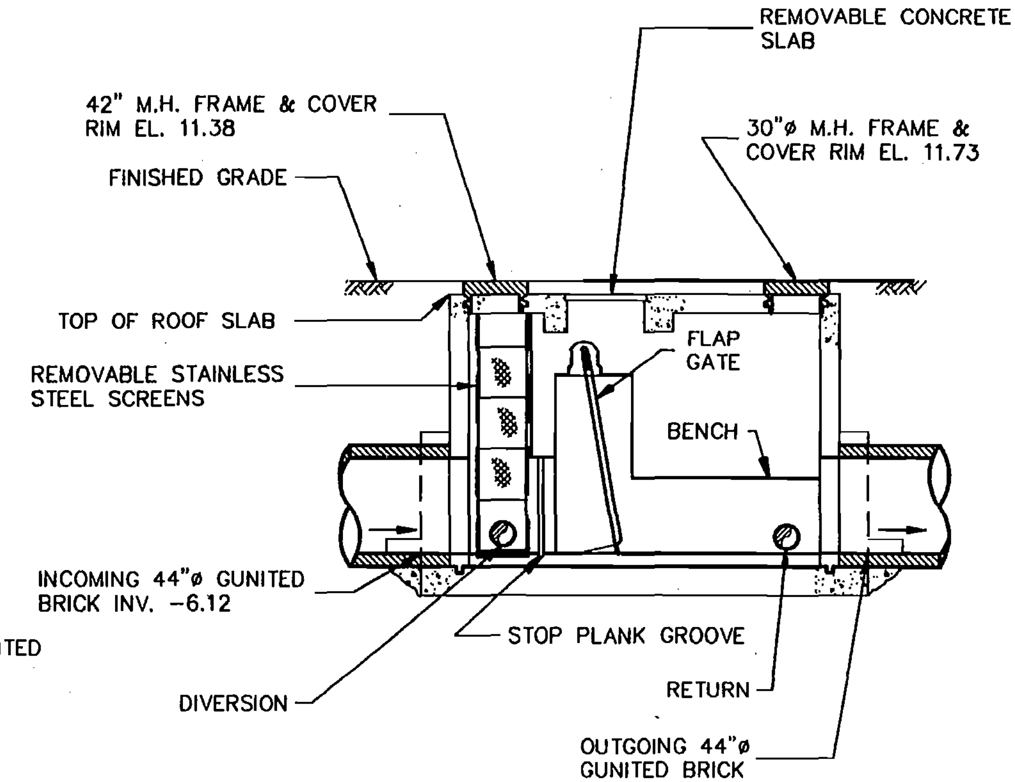


SECTIONAL PLAN

NOT TO SCALE

LEGEND

→ DRY WEATHER FLOW
- - -→ WET WEATHER FLOW



SECTION A-A

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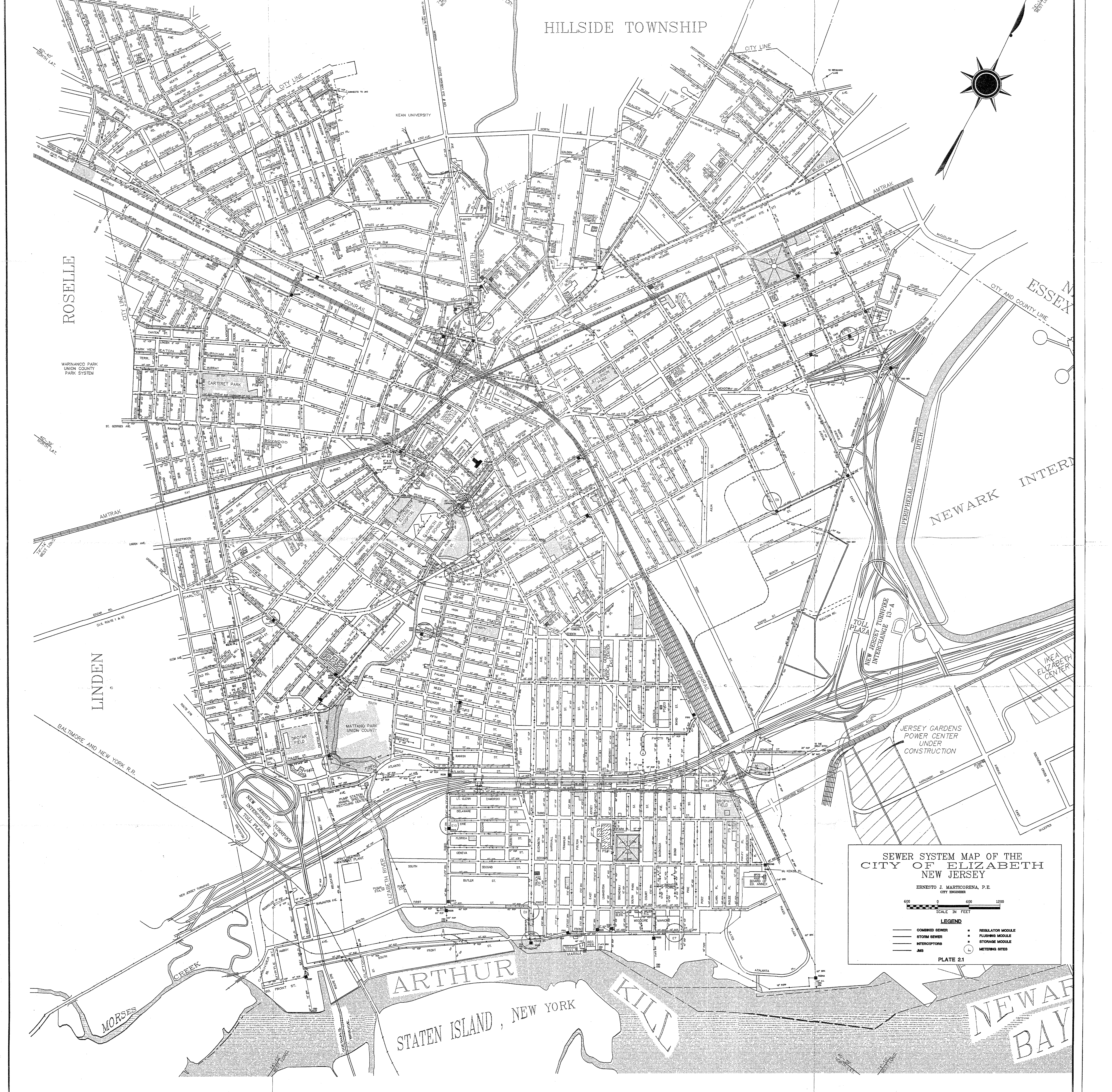
CITY OF ELIZABETH
UNION COUNTY, NEW JERSEY

CSO SOLIDS/FLOATABLES CONTROL FACILITIES

PLATE 2.8-14.2 STORAGE MODULE 14 SCHEMATIC

Designed	Drawn	Checked	Approved	Date	Scale
J.J.M.	J.J.M.	J.A.F.			N.T.S.



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ORIGINAL ISSUE 03/02/98 PREPARED BY S. RINALDI

22

Dr. Berkowitz

To: Bob Soboleski
Thru: Fred Bertolino 7/20
26 JUL 1984

Elizabethtown Gas COMPANY
A NATIONAL UTILITIES & INDUSTRIES COMPANY
[redacted] ELIZABETHTOWN PLAZA • ELIZABETH, NEW JERSEY 07207 • (201) 289-5000
ONE BROWN AVENUE, ISELIN, NEW JERSEY 08830-9990

July 6, 1984

Dr. Marwan M. Sadat, P.E.
Director, Division of Waste Management
Department of Environmental Protection
32 E. Hanover Street
CN 028
Trenton, NJ 08625

Dear Dr. Sadat:

The attached information is provided to you in response to your information request dated February 29, 1984. The response covers six sites; two in Elizabeth, and one each in Rahway, Perth Amboy, Flemington and Newton. We have kept the numbering of the questions as they appeared on your original letter.

On-site data only exists for the Erie Street Plant in Elizabeth in the form of soil boring data from studies done for structures which were subsequently installed. This data has been included.

In the section on Ground and Surface Water Use, the questions have been answered to the best of our ability, however, the underlying aquifer in use may be so deep that it may not be an aquifer of concern. Your questions did not address this differentiation of aquifers and aquifers of concern, and we trust your department has the expertise in regional geology to fairly interpret the data provided.

If you have any questions please contact me at 201/289-5000, Ext. 168.

Respectfully submitted,

Barbara Altenburg

Barbara Altenburg, P.E.
Project Manager

BJA/bl
Attach.

27/107

BBA000001

NJ DEP INFORMATION REQUEST

ERIE STREET PLANT

I. SITE BACKGROUND

1. Location: 3rd Ave. at Florida St., Elizabeth
   Map attached.

2. Site Description:

   a. See sketch.

   b. Buildings and tanks are as indicated on sketch in 2.a. The entire property is secured with chain link fence and 24 hour guard. The yard is mostly covered by crushed stone and fill.

3. History of Ownership and Use:

   a. Elizabethtown Gas Co. has owned the property since 1857. Gas was manufactured until 1952 on a daily basis. From 1952 until 1971 gas was only manufactured on the coldest winter days when it was needed to help meet demand. The manufacturing plant and most of the buildings were removed in 1978. The remaining structures include two large vacant brick buildings which are used for gas mixing and distribution operations (including propane/air and LNG), three buildings which are used for part of the operations function and for the gas dispatching control center, a water pump house for the fire protection system, a water storage tank, two gas holders, a battery of propane storage tanks and a liquified natural gas storage tank, and an unused oil tank.

   b. Although actual waste handling practices at the plant are largely unknown, areas of the yard were designated for waste storage. Concrete bins were used to separate and store tars and other oils were kept in above ground tanks. In the early days of the plant's operation (prior to 1920's) tars were removed by rail car and sold to asphalt companies and a refinery. Tars were later sold and transported off-site by truck.

   c. Materials which were not marketable, such as poor quality tars which were recovered from the machinery when it was cleaned and oils which were pumped out of the mains in a mixture of water, were probably deposited on the site. There is evidence of these products in the center of the property where the coal and coke piles were. It was thought that coal and coke would act as a filter on these waste materials.

3. d. Since the material is buried and underlain by a layer of relatively impermeable clay, no remedial action has been taken other than filtration of stormwater run-off.

   e. On April 17, 1984 a citation was issued for a violation of 33USC1161 during the start up test for a new fire protection system at the plant.

4. It is expected that future use of the site will be the same as present use.

II. SITE CHARACTERISTICS

A. Land Use:

1. The site is situated in an area with mixed urban/industrial/commercial land use. Northeast of the site, across 3rd Avenue, there is a residential area. To the southeast is a highly industrialized area including a truck terminal and chemical storage yards. ConRail and the Turnpike border the property on the northwest and the Elizabeth River runs southwest of the property. The Arthur Kill is within a mile of the site.

2. The average population density within a 2 mile radius of the plant is approximately 7,000 people per square mile.

3. The site is secured by 8 foot chain link fencing topped with barbed wire. A guard is on duty 24 hours a day and plant personnel monitor a closed circuit television scan of the plant main entrance.

B. Site Terrain:

1. Average slope of the site is less than 2%. See topographic map.

2. The nearest downslope surface water is the Elizabeth River. At this location there is significant tidal influence on the river. It joins the Arthur Kill within a mile of the site and there is no known use of this body of water for other than shipping.

3. The terrain slopes slightly toward the river, however the Corps of Engineers has built a 12-15 foot high embankment between the river and the site.

4. The site ranges from 6 to 12 feet above sea level. Adjacent properties are at the same general elevations with the exception of the Turnpike and ConRail which are much higher.

C. Ground and Surface Water Use

1. There are no known uses of the aquifer underlying the site within a three mile radius. Our search did not indicate any well records.

2. There are no known potable wells within 3 miles of the site.

3. There are no water-supply wells within 3 miles of the site.

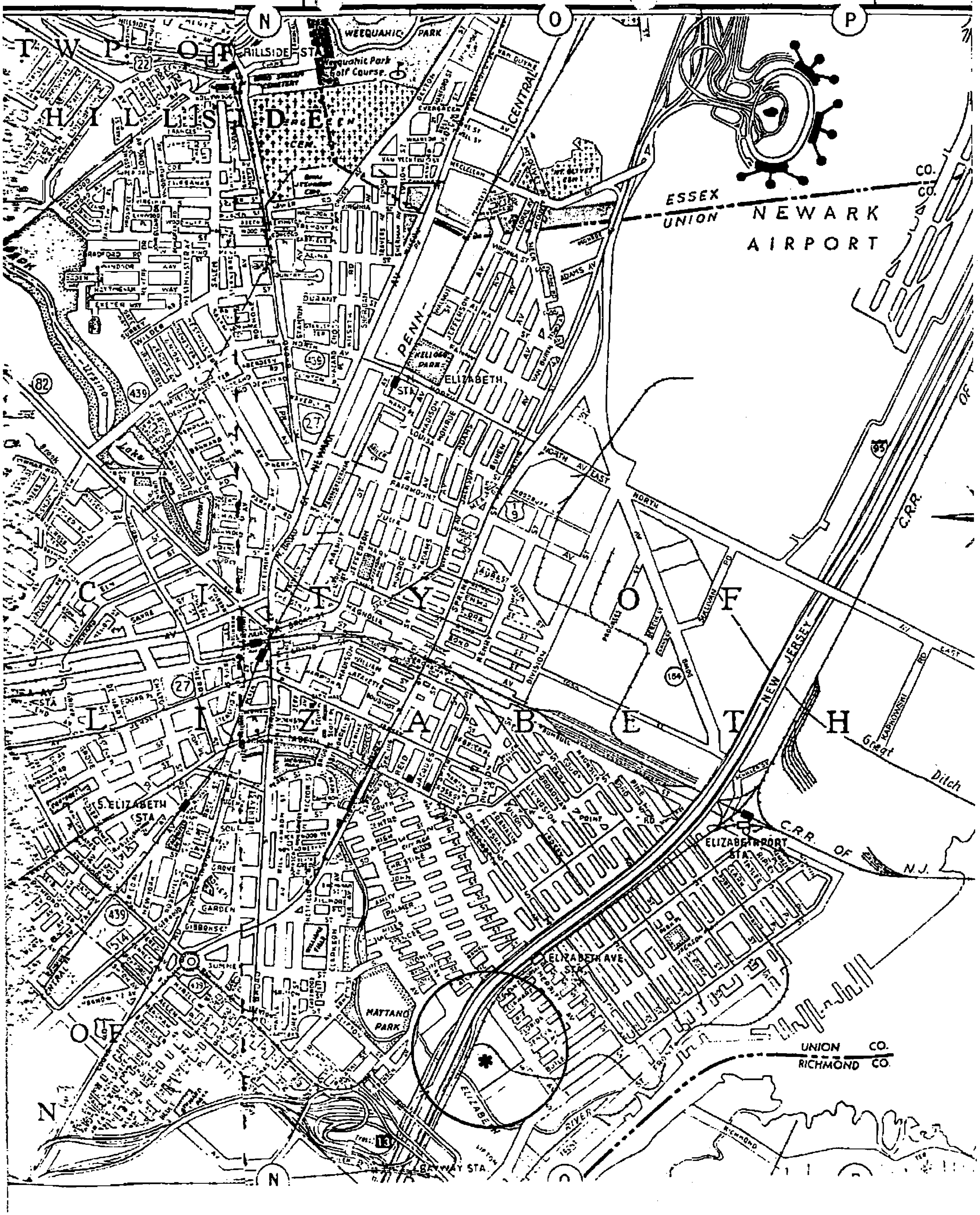
4. Uses of surface water within 3 miles of the site are restricted to shipping.

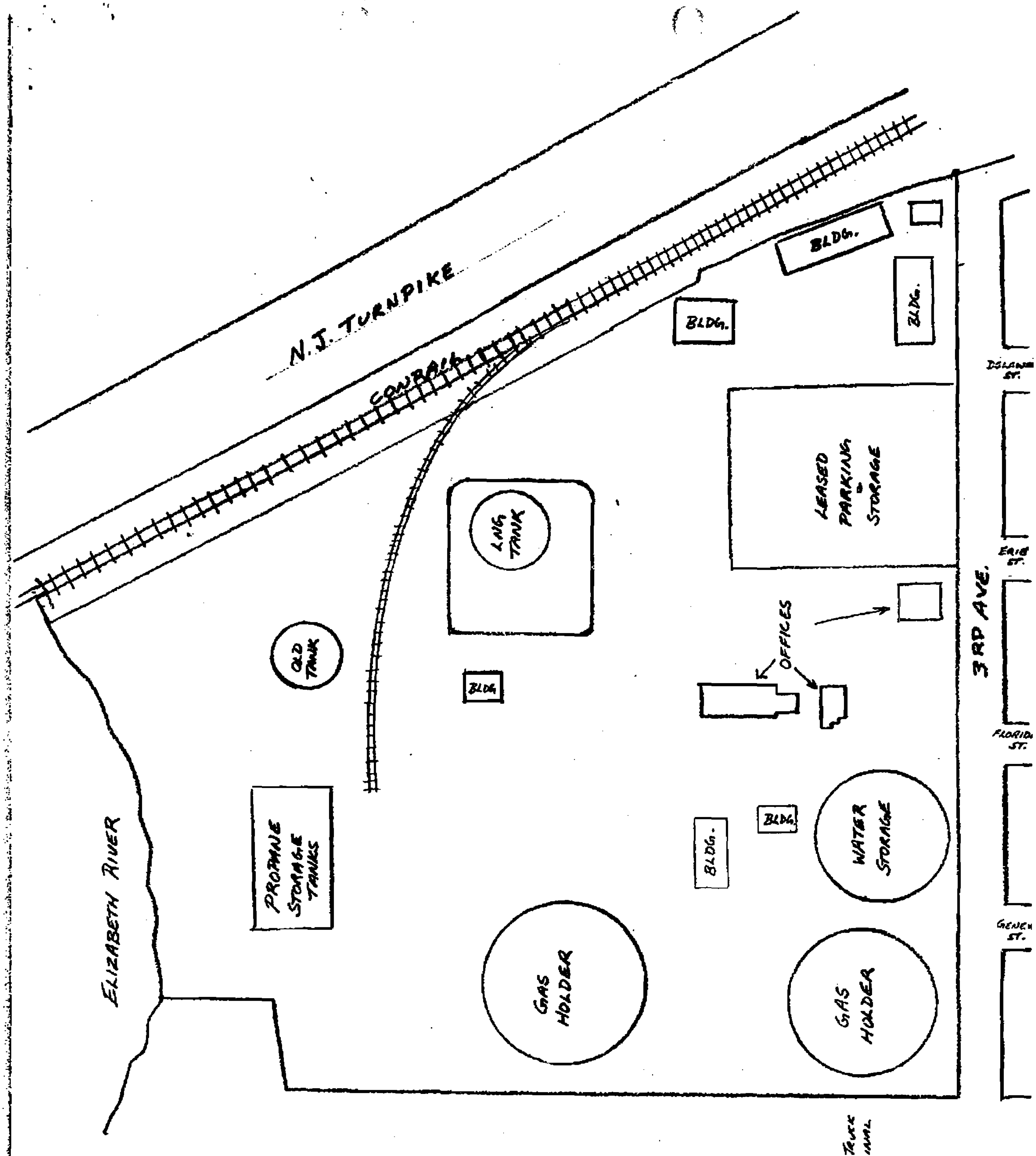
5. There are no surface water supply intakes within 3 miles downstream of the site.

D. Site Contamination

a. See boring data.

FOR ADJOINING AREA SEE ... COUNTY MAP NO. 10 PAGE 50 | SEE ESSEX CO





ERIE STREET PLANT

ELIZABETH, N.J.

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State of New Jersey

DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF WATER RESOURCES
CN 029
TRENTON, NEW JERSEY 08625

George G. McCann, P.E.
Acting Director

Water Quality Management

DIRK C. HOFMAN, P.E.
DEPUTY DIRECTOR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Barbara Altenburg
Elizabethtown Gas Company
One Brown Plaza
Iselin, NJ 08830-9990

JUL 31 1986

Re: Issuance of Emergency New Jersey Pollutant Discharge Elimination System (NJPDES) Discharge to Ground Water (DGW) Permit NJ0063746.

Dear Ms. Altenburg:

Attached is an emergency New Jersey Pollutant Discharge Elimination System (NJPDES) permit that has been issued pursuant to N.J.A.C. 7:14A-1 et seq. This NJPDES permit is issued under the authority of the New Jersey Water Pollution Control Act and upon issuance of the permit shall supersede any previously existing ground water monitoring requirements that the above named facility may have implemented.

Please be aware of the following provisions of this permit:

1) This permit is effective for ninety days. Discharge for the pump test is limited to three consecutive calender days within the ninety day period. Continuation of the pump test beyond three days or for more than 25,000 gallons requires the reissuance of the permit. The Department shall be notified of the exact dates of the pumping at least one week before the start of the pump test.

2) Any existing wells must be certified by a licensed New Jersey Professional Engineer, a duly authorized representative, or an executive officer, and must be surveyed by a licensed New Jersey Land Surveyor. If the construction details or location are unknown or cannot be determined, then a new well must be drilled. Certifications (Enclosed Forms A and B) to the location and construction of the monitoring wells shall be submitted within 60 days of the effective date of the permit. Failure to submit the these certification forms will result in the invalidation of the

ground water monitoring data and will be deemed noncompliance with the permit.

3) New Jersey State well permits shall be obtained for all new wells and any existing wells that were drilled without valid well permits.

4) Samples must be analyzed by a New Jersey Certified laboratory at the frequency and for the parameters specified in the permit.

5) Data must be submitted on the enclosed state forms. Data which is not submitted on the state forms does not meet the reporting requirements of this permit. Data submitted for water analysis from uncertified wells is likewise unacceptable and does not fulfill the reporting requirements of the permit.

6) Please be advised that failure to meet the conditions of the permit can result in the imposition of substantial administrative, civil, and criminal penalties.

The appearance of the public notice in the newspapers marks the commencement of the mandatory 30-day public comment period required by Section 8.1 of the NJPDES regulations. During this time frame, both the permittee and concerned citizens may offer comments regarding the terms and conditions of this permit. All comments must be submitted within the appropriate time frame and in writing to:

Administrator
NJDEP Division of Water Resources
Water Quality Management Element
CN-029
Trenton, New Jersey 08625

If you have any questions regarding this permit, please contact Stephen J. Urbanik at the Land Application of Wastewater Section of the Bureau of Ground Water Quality Management at (609) 292-0424.

Sincerely yours,

Robert Berg, Chief
Bureau of Ground Water
Quality Management

WQM204

Enclosures

Let's protect our earth

STATE OF NEW JERSEY
DEPARTMENT OF ENVIRONMENTAL PROTECTION
CN 402
Trenton, N.J. 08625

PERMIT

The New Jersey Department of Environmental Protection grants this permit in accordance with your application, attachments accompanying same application, and applicable laws and regulations. This permit is also subject to the further conditions and stipulations enumerated in the supporting documents which are agreed to by the permittee upon acceptance of the permit.

Permit No.	Issuance Date	Effective Date	Expiration Date
NJ# 0063746	08/01/86	08/01/86	11/01/86

Name and Address of Applicant	Location of Activity/Facility	Name and Address of Owner
Elizabethtown Gas Company One Brown Plaza Iselin, NJ 08830-9990	Third Avenue & Florida Street Lot No. 1381, Block No. 5 Elizabeth, NJ 07206	Elizabethtown Gas Company One Brown Plaza Iselin, NJ 08830-9990

Issuing Division	Type of Permit	Statute(s)	Application No.
WATER RESOURCES	NJPDES-DGW	N.J.S.A. 58:10A-1 et seq.	NJ#0063746

This permit grants permission to:

Perform a one-to-two hour aquifer pump test in which four (out of 10 total) ground water monitoring wells will be pumped at a rate of between ten-to-fifteen gallons per minute (between 2400-to-7200 gallons total) and recharged to the ground at the well sites over a one-to-two day period. Well sites shall be diked to prevent surface water discharge.

This permit does not allow for discharge to surface water, storm sewer, or indirect discharge to a sewerage authority treatment works.

Ground water quality will be monitored according to the general and specific conditions of the permit.

Approved by the Department of Environmental Protection

ARNOLD SCHIFFMAN, ADMINISTRATOR
WATER QUALITY MANAGEMENT

DATE

* *The word permit means "approval, certification, registration, etc."*

(GENERAL CONDITIONS ARE ON THE REVERSE SIDE.)

Form DEP-007 (8/83)

New Jersey Department of Environmental Protection
Division of Water Resources
Bureau of Ground Water Quality Management
CN-029
Trenton, New Jersey 08625
(609) 292-0424

Public Notice

NOTICE: ISSUANCE OF EMERGENCY NJPDES/DGW PERMIT NJ0063746.

Notice is hereby given that the New Jersey Department of Environmental Protection intends to issue to:

The Elizabethtown Gas Company
Third Avenue and Florida Street
Elizabeth

an Emergency New Jersey Pollutant Discharge Elimination System (NJPDES) Permit to discharge to ground water of the state of New Jersey.

The facility is a propane, liquified natural gas (LNG), and natural gas storage and transfer facility. This emergency permit is being issued to allow for the temporary pumping and infiltration of ground water for a pump test to evaluate the characteristics of the local aquifer.

For an existing facility, issuance of the NJPDES permit is the enforcement mechanism by which pollutant discharges are brought into compliance with standards.

This notice is being given to inform the public that NJDEP has prepared an emergency NJPDES permit. This emergency permit contains conditions necessary to implement the provisions of the "Regulations Concerning the New Jersey Pollutant Discharge Elimination System" (N.J.A.C. 7:14A-1 et seq.), which were promulgated pursuant to the authority of the New Jersey "Water Pollution Control Act" (N.J.S.A. 58:10A-1 et seq.).

The emergency permit prepared by NJDEP is based on the administrative record which is on file at the offices of the NJDEP, Division of Water Resources, located at 1474 Prospect Street in the Township of Ewing, Mercer County, New Jersey. It is available for inspection, by appointment, between 8:30 A.M. and 4:00 P.M., Monday through Friday. Appointments for inspection may be scheduled by calling (609) 984-4428.

Interested persons may submit written comments on the emergency permit to the Administrator, Water Quality Management, at the address cited above. All comments shall be submitted within 30 days of the date of this public notice. All persons, including applicants, who believe that any condition of this emergency permit is inappropriate or that the Department's decision to issue this emergency permit is inappropriate, must raise all reasonably ascertainable issues and submit all reasonably available arguments and factual grounds supporting their position, including all supporting material, by the close of the public comment period. All comments submitted by interested persons in response to this notice, within the time limit, will be considered by the NJDEP with respect to the permit. The Department will respond to all significant and timely comments. The applicant and each person who has submitted written comments will receive notice of NJDEP's response.

Any interested person may request in writing that NJDEP hold a nonadversarial public hearing on the emergency permit. This request shall state the nature of the issues to be raised in the proposed hearing and shall be submitted within 30 days of the date of this public notice to the Administrator, Water Quality Management at the address cited above. A public hearing will be conducted whenever the NJDEP determines that there is a significant degree of public interest in the permit decision. If a public hearing is held, the public comment period in this notice shall automatically be extended to the close of the public hearing.

Arnold Schiffman
Administrator
Water Quality Management

FACT SHEET
FOR THE NJPDES PERMIT TO DISCHARGE
INTO THE GROUND WATERS OF THE STATE

Name and Address of Applicant:

Elizabethtown Gas Company
One Brown Plaza
Iselin, NJ 08830-9990

Name and Address of Facility Where Discharge Occurs:

Elizabethtown Gas Company
Third Avenue and Florida Street
Lot No. 1381, Block No. 5
Elizabeth, NJ 07206

Receiving Water:

Ground Waters of the State. The site is underlain by the Triassic Brunswick Formation.

Description of Facility:

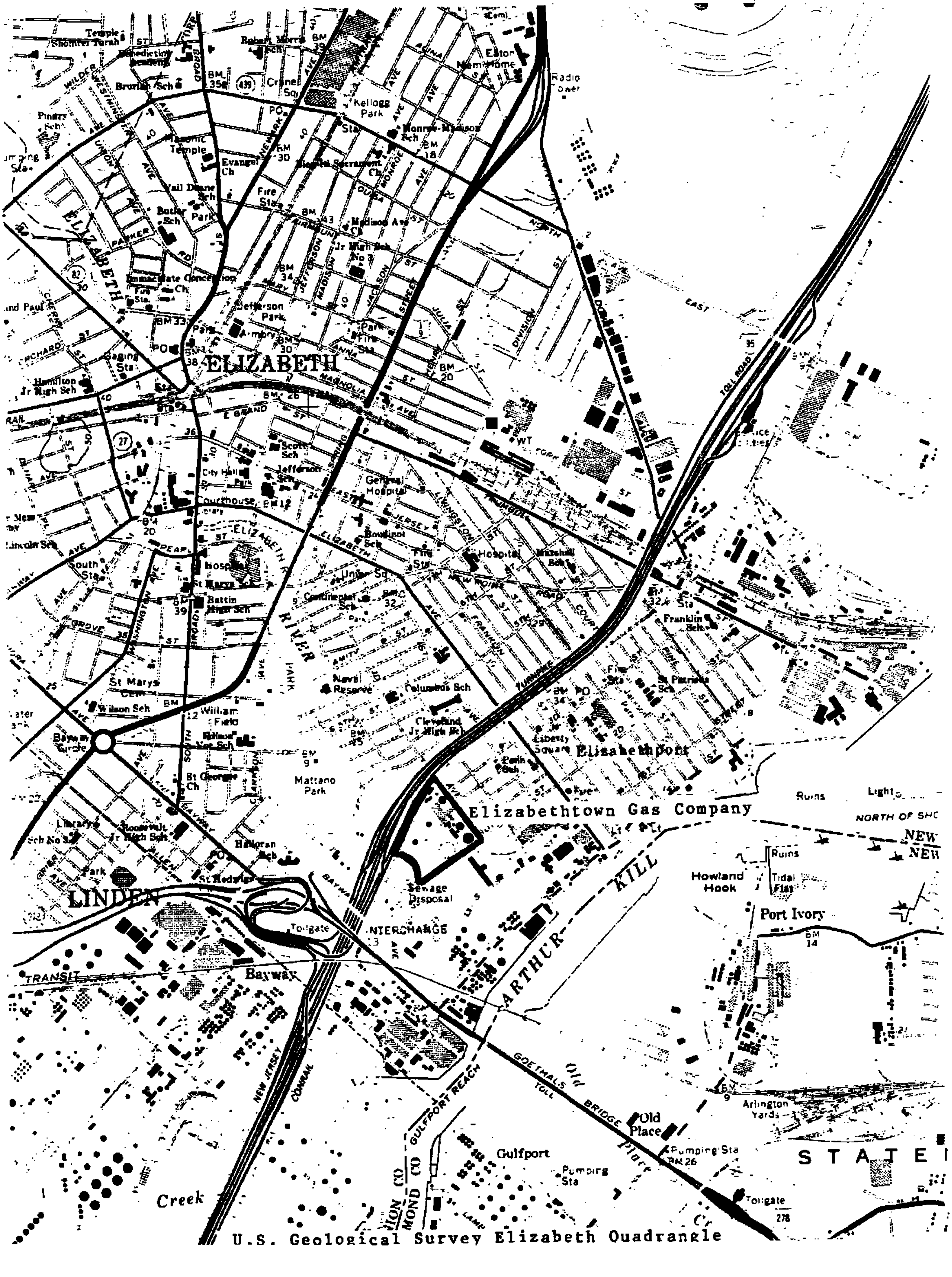
The site is a propane, liquified natural gas (LNG), and natural gas storage and transfer (rail, truck, and pipeline) facility. Aquifer testing will be performed by utilizing four of ten monitoring wells. Water will be recharged by infiltration through diked areas of the crushed stone surface. All wells at the site will be sampled for base/neutral compounds, volatile organic compounds, cyanide, chromium, lead, and petroleum hydrocarbons before the test.

Description of Discharge:

Between 2400 to 7200 gallons (10 to 15 gallons per minute (gpm) at one to two hours, estimated) of pumped ground water. The water (tested in 1984 over Ground Water Quality Standards for base/neutral compounds, volatile organic compounds, and cyanide) is to be pumped and recharged to the ground as part of an aquifer characterization test. Permit limits maximum discharge to 25,000 gallons.

Permit Conditions:

According to the attached General and Specific Conditions.



U.S. Geological Survey Elizabeth Quadrangle

CHECKLIST OF PARTS AND MODULES COMPRISING THIS NJPDES PERMIT

1. Cover Page

2. Checklist

3. Part I (General Conditions for All NJPDES Discharge Permits)

4. Part II - Additional General Conditions for the types of NJPDES Permits checked as follows:

   ____ Part II - A (Municipal/Sanitary)

   ____ Part II - B/C (Industrial/Commercial/Thermal)

   ____ Part II - L (SIU)

   ____ Part II - IWMF (Industrial Waste Management Facility)

   ____ Part II - DGW Specify type(s): ____________

5. Part III - Effluent Limitations and Monitoring Requirements

   ____ Part III - A

   ____ Part III - B/C

   ____ Part III - L

   X Part III - DGW Specify type(s): Ground Water Monitoring Requirements

6. Part IV - Special Conditions

   ____ Part IV - A

   ____ Part IV - B/C

   ____ Part IV - L

   ____ Part IV - IWMF

   X Part IV - DGW

STATE OF NEW JERSEY
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF WATER RESOURCES

GENERAL CONDITIONS FOR ALL NJPDES DISCHARGE PERMITS

1. Duty to Comply

A. The permittee shall comply with all conditions of this New Jersey Pollutant Discharge Elimination System (NJPDES) permit. No pollutant shall be discharged more frequently than authorized or at a level in excess of that which is authorized by the permit. The discharge of any pollutant not specifically authorized in the NJPDES permit or listed and quantified in the NJPDES application shall constitute a violation of the permit, unless the permittee can prove by clear and convincing evidence that the discharge of the unauthorized pollutant did not result from any of the permittee's activities which contribute to the generation of its wastewaters. Any permit noncompliance constitutes a violation of the New Jersey Water Pollution Control Act (N.J.S.A. 58:10A-1 et seq.; hereinafter referred to as the State Act) or other authority of the NJPDES regulations (N.J.A.C. 7:14A-1 et seq.) and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

B. A permittee shall not achieve any effluent concentration by dilution. Nor shall a permittee increase the use of process water or cooling water or otherwise attempt to dilute a discharge as a partial or complete substitute for adequate treatment to achieve permit limitations or water quality standards.

C. The permittee shall comply with applicable effluent standards or prohibitions established under Section 307 (a) of the "Federal Water Pollution Control Act" (PL 92-500 et seq.; hereinafter referred to as the Federal Act) and Section 4 of the State Act for toxic pollutants within the time provided in the regulations that establish these standards or prohibitions, even if the permit has not yet been modified to incorporate the requirement.

D. The State Act provides that any person who violates a permit condition implementing the State Act is subject to a civil penalty not to exceed $10,000 per day of such violation. Any person who willfully or negligently violates permit conditions implementing the State Act is subject to a fine of not less than $2,500 nor more than $25,000 per day of violation, or by imprisonment for not more than 1 year, or both.

E. The permittee is required to comply with all other applicable federal, state and local rules, regulations, or ordinances. The issuance of this permit shall not be considered as a waiver of any other requirements.

2. Permit Expiration

This permit and the authorization to discharge shall expire at midnight on the expiration date of the permit. The permittee shall not discharge after the above date of expiration of the permit.

A. Duty to Reapply. If the permittee wishes to continue an activity regulated by a NJPDES permit after the expiration date of the permit, the permittee shall apply for and obtain a new permit. (If the activity is to be continued, the permittee shall complete, sign, and submit such information, forms, and fees as are required by the Department no later than 180 days before the expiration date.) The permittee shall follow the requirements stated in paragraph 12.A. when signing any application.

B. Continuation of Expiring Permits

(1) The conditions of an expired permit are continued in force pursuant to the "Administrative Procedure Act," N.J.S.A. 52:14B-11, until the effective date of a new permit if:

a. The permittee has submitted a timely and complete application for renewal as provided in Sections 2.1 and (3.2 DSW) (4.4 IWMF) (5.8 UIC) and Subchapter 10 of the NJPDES Regulations; and

b. The Department through no fault of the permittee, does not issue a new permit with an effective date under Section 8.6 of the NJPDES Regulations on or before the expiration date of the previous permit (e.g., when issuance is impracticable due to time or resource constraints).

(2) Permits continued under this section remain fully effective and enforceable.

(3) Enforcement. When the permittee is not in compliance with the conditions of the expiring or expired permit the Department may choose to do any or all of the following:

a. Initiate enforcement action based upon the permit which has been continued;

b. Issue a notice of intent to deny the new permit under Section 8.1 of the NJPDES Regulations. If the permit is denied, the owner or operator would then be required to cease the activities authorized by the continued permit or be subject to enforcement action for operating without a permit;

c. Issue a new permit under Subchapters 7 and 8 of the NJPDES Regulations with appropriate conditions; or

d. Take other actions authorized by the NJPDES Regulations or the State Act.

3. Duty to Halt or Reduce Activity

A. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

B. Upon reduction, loss, or failure of the treatment facility, the permittee shall, to the extent necessary to maintain compliance with its permit, control production or discharges or both until the facility is restored to its permitted limits or an alternative method of treatment is provided. This requirement applies, for example, when the primary source of power of the treatment facility fails or is reduced or lost.

4. Duty to Mitigate

The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit, including but not limited to accelerated and/or additional types of monitoring, temporary repairs or other mitigating measures.

5. Proper Operation, Maintenance and Licensing

A. The permittee shall at all times maintain in good working order and operate as efficiently as possible all treatment works, facilities, and systems of treatment and control (and related appurtenances) for collection and treatment which are installed or used by the permittee for water pollution control and abatement to achieve compliance with the terms and conditions of the permit. Proper operation and maintenance includes but is not limited to effective performance based or designed facility removals, adequate funding, effective management, adequate operator staffing and training and adequate laboratory and process controls including appropriate quality assurance procedures as described in 40 CFR Part 136 and applicable State Law and regulations. All permittees who operate a treatment works, except for sanitary landfills and land application of sludge or septage, must satisfy the licensing requirements of the "Licensing of Operators of Wastewater and Water Systems" N.J.S.A. 58:11-64 et seq. or other applicable law. This paragraph requires the operation of back-up or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit or where required by applicable law or regulation.

B. Facilities Operation and Operator Certification. The operation of any treatment works shall be under the supervision of an operator on the first day of operation of the treatment works and continually thereafter in accordance with paragraph 5.A above. The operator shall meet the requirements of the Department of Environmental Protection of the State of New Jersey pursuant to the provisions of N.J.S.A. 58:11-64 et seq and amendments thereto. The name of the proposed operator shall be submitted to this Department in order that his qualifications may be determined prior to inititating operation of the proposed treatment works.

6. Permit Actions

A. This permit may be modified, suspended, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

B. Causes for modification, revocation and reissuance, and suspension are set forth in N.J.A.C. 7:14A-2.12 et seq.

C. The following are causes for terminating or modifying a permit during its term, or for denying a permit renewal application:

(1) Noncompliance by the permittee with any condition of the permit;

(2) Failure to pay applicable fees (N.J.A.C. 7:14A-1.8), including the annual NJPDES permit fee which has been assessed by the New Jersey Department of Environmental Protection (NJDEP, hereinafter referred to as the Department);

(3) The permittee's failure in the application or during the permit issuance process of a National Pollutant Discharge Elimination System (NPDES), Discharge Allocation Certificate (DAC), NJPDES, Treatment Works Approval (TWA) or Construct and Operate permit to disclose fully all relevant facts, or the permittee's misrepresentation of any permit condition;

(4) A determination that the permitted activity endangers human health or the environment and can only be regulated to acceptable levels by permit modification or termination;

(5) When there is a change in any condition that requires either a temporary or a permanent reduction or elimination of any discharge controlled by the permit (for example, plant closure or termination of discharge by connection to a Domestic Treatment Works (DTW);

(6) The nonconformance of the discharge with any applicable facility, basin or areawide plans;

(7) If such permit is inconsistent with any duly promulgated effluent limitation, permit, regulation, statute, or other applicable state or federal law; or

(8) If a toxic effluent standard or prohibition is established pursuant to New Jersey Water Pollution Control Act N.J.S.A. 58:10A-1 et seq. or the regulations adopted pursuant to it, for a toxic pollutant which is present in the discharge, and such is more stringent than any limitation for such pollutant in this permit, this permit shall be revised or modified in accordance with the toxic effluent standard or prohibition and the permittee so notified of the revision or modification and date of required compliance.

7. Property Rights, Liability, and Other Laws

A. This permit does not convey and property rights of any sort or any exclusive privileges.

B. Nothing in this permit shall be deemed to preclude the institution of any legal action nor relieve the permittee from any responsibilities or penalties to which the permittee is or may be subject to under any federal, state or local law or regulation.

C. Nothing in this permit shall be construed to exempt the permittee from complying with the rules, regulations, policies, and/or laws lodged in any agency or subdivision in this State having legal jurisdiction.

8. Duty to Provide Information

A. The permittee shall furnish to the Director, Division of Water Resources, NJDEP, (hereinafter referred to as the Director),within a reasonable time, any information which the Director may request to determine whether cause exists for modifying, suspending, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit.

B. Where the permittee becomes aware that he has failed to submit any relevant facts in a permit application, or has submitted incorrect information in a permit application or in any report to the Director, the permittee shall promptly submit such facts or information.

9. Inspection and Entry

A. The permittee shall allow the Regional Administrator of the United States Environmental Protection Agency (USEPA), the Department, or any authorized representative(s), upon the presentation of credentials and other documents as may be required by law, to:

(1) Enter upon the permittee's premises where a discharge source is or might be located or in which monitoring equipment or records required by a permit are kept, for purposes of inspection, sampling, copying or photographing. Photography shall be allowed only as related to the discharge;

(2) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

(3) Inspect, at reasonable times, any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

(4) Sample or monitor, at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the State Act, any substances or parameters at any location. This shall include, but not be limited to, the drilling or installation of monitoring wells for

the purpose of obtaining samples of ground water, soil and vegetation and measuring ground water elevations.

B. Any refusal by the permittee, facility land owner(s), facility lessee(s), their agents, or any other person(s) with legal authority, to allow entry to the authorized representatives of the NJDEP and/or USEPA shall constitute grounds for suspension, revocation and/or termination of this permit.

C. By acceptance of this permit, the permittee hereby agrees, consents and authorizes the representatives of the NJDEP and/or USEPA to present a copy of this permit to any municipal or state police officer having jurisdiction over the premises occupied by the permittee in order to have said officer effectuate compliance with the right of entry, should the permittee at any time refuse to allow entry to said inspectors.

D. By acceptance of this permit, the permittee waives all rights to prevent inspections by authorized representatives of the NJDEP and/or USEPA to determine the extent of compliance with any and all conditions of this permit and agrees not to, in any manner, seek to charge said representatives with the civil or criminal act of trespass when they enter the premises occupied by the permittee in accordance with the provisions of this authorization as set forth hereinabove.

10. Ground Water Monitoring Wells

The permittee shall install and maintain ground water monitoring wells if required by this permit at locations and according to specifications provided by the Department. All permit required monitoring wells shall be installed within 30 days of the Effective Date of the Permit. The monitoring wells shall provide turbidity-free water at a minimum rate of two gallons per minute or what the formation will yield with a properly installed and developed ground water monitoring well.

When a monitoring well cannot be used for the purpose of sample collection or ground water level measurements, the permittee shall replace the well at his own expense within 30 days of the missed sampling and/or measurement date. Said unuseable wells shall be sealed, also at the permittee's own expense, in accordance with Department well sealing specifications within the same 30 day period in which the well is replaced. Monitoring wells as required in this permit shall be considered as a monitoring device, which are required to be maintained under the provisions of the New Jersey Water Pollution Control Act N.J.S.A. 58:10A-10(f).

All monitoring wells must be installed by a New Jersey licensed well driller. The elevation to the nearest hundredth of a foot of the top of each well casing shall be established by a New Jersey licensed land surveyor within 30 days of the installation of the monitoring wells. The elevation established shall be in relation to the New Jersey geodetic control datum. Ground water monitoring wells and all point source discharges to ground water shall be located by horizontal control (latitude and longitude) using third order work, class II specification and by vertical control (elevation) using third order work. Within 30 days of the installation date of the monitor well, the permittee shall submit to the Department completed "Ground Water Monitoring Well Certifications - Forms A and B for each well required to be sampled by the permit. Within 60 days of the Effective Date of the Permit, the permittee shall submit to the Department a plot plan of the facility showing the location of all discharges and the ground water monitoring well locations. The scale of the plot plan shall be at least one inch equals fifty (50) feet.

Each ground water monitoring well casing shall have permanently affixed to it a monitoring well number to be assigned by the Department, elevation of the top of the well casing, elevation of the top of the well casing above the ground level and latitude and longitude of the monitoring well.

11. Monitoring and Records

A. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.

B. The State Act provides that any person who falsifies, tampers with, or knowingly renders inaccurate any monitoring device or method required to be maintained under this permit shall, upon conviction, be punished by a fine of no more than $10,000 per violation, or by imprisonment for not more than 6 months per violation, or by both. This is specifically intended to include, but not be limited to, ground water monitoring wells and lysimeters.

C. The applicant shall perform all analyses in accordance with the analytical test procedures approved under 40 CFR Part 136. Where no approved test procedure is available, the applicant must indicate a suitable analytical procedure and must provide the Department with literature references or a detailed description of the procedure. The Department must approve the test procedure before it is used. The laboratory performing the analyses for compliance with this permit must be approved and/or certified by the Department for the analysis of those specific parameters. Information concerning laboratory approval and/or certification may be obtained from:

New Jersey Department of Environmental Protection
Office of Quality Assurance
CN 409
Trenton, New Jersey 08625
(609) 292-3950

D. The permittee shall retain records of all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least 5 years from the date of the sample, measurement, report or application. This period may be extended by request of the Department at any time.

E. Records of monitoring information shall include:

(1) The date, exact place, and time of sampling or measurements;

(2) The individual(s) who performed the sampling or measurements;

(3) The date(s) analyses were performed;

(4) The individual(s) who performed the analyses;

(5) The analytical techniques or methods used; and

(6) The results of such analyses.

F. Monitoring results shall be reported on a Discharge Monitoring Report (DMR) and/or on the Department's Monitoring Report Form (MRF); or, where these forms do not apply, in another format approved by the Department.

G. If the permittee monitors any pollutant more frequently than required by the permit, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR, MRF, or other approved format.

H. Calculations for all limitations which require averaging of measurements shall utilize an arithmetic mean unless otherwise specified by the Department in the permit.

I. Discharge Monitoring Reports

(1) Monitoring results shall be summarized and reported on the appropriate Monitoring Report Forms following the completed reporting period. Signed copies of these, and all other reports required herein, shall be submitted to the following address:

Water Quality Management
Division of Water Resources
CN 029
Trenton, New Jersey 08625
ATTN: Monitoring Reports

(2) If a contract laboratory is utilized, the permittee shall submit the name and address of the laboratory and the parameters analyzed at the time it submits its monitoring reports (See Section 11.E. above). Any change in the contract laboratory being used or the parameters analyzed shall be reported prior to or together with the monitoring report covering the period during which the change was made.

J. Monitoring Reports. Monitoring results shall be reported at the intervals and starting date specified elsewhere in this permit.

K. Compliance Schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 14 days following each schedule date.

12. Signatory Requirement

A. Signature Requirements. All permit applications, except those submitted for Class II wells for a UIC discharge (see paragraph B) shall be signed as follows:

(1) For a corporation, by a principal executive officer of at least the level of vice president;

(2) For a partnership or sole proprietorship, by a general partner or the proprietor, respectively; or

(3) For a municipality, state, federal or other public agency, by either a principal executiv officer or ranking elected official.

B. Reports. All reports required by permits, other information requested by the Department and all permit applications submitted for Class II wells under N.J.A.C. 7:14A-5.8 shall be signed by a person described in paragraph A of this section or by a duly authorized representative only if:

(1) The authorization is made in writing by a person described in paragraph A of this section;

(2) The authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as a position of plant manager, operator of a well or well field, superintendent or person of equivalent responsibility; and

(3) The written authorization is submitted to the Department.

C. Changes to Authorization. If an authorization under paragraph B of this section is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph B of this section shall be submitted to the Department prior to or together with any reports, information, or applications to be signed by an authorized representative.

D. Certification (N.J.A.C. 7:14A-2.4(d)). Any person signing any document under paragraph A or B of this section shall make the following certification: "I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe the submitted information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment."

E. False Statements. Any person who knowingly makes a false statement, representation, or certification in any application, record, or other document filed or required to be maintained under the State Act shall upon conviction, be subject to a fine of not more than $10,000.00 or by imprisonment for not more than 6 months or by both.

13. Reporting Changes and Violations

A. Planned Changes. The permittee shall give notice to the Department as soon as possible of any planned physical alterations or additions to the permitted facility. The permittee shall comply with N.J.A.C. 7:14A-12.1 et seq. which requires approval for building, installing, modifying, or operating treatment works. (NOTE: Sewer Extensions require such an approval. A connection of a single building through which less than 2000 gpd flows by gravity through a single lateral is exempt from the requirement to obtain the approval of this Department.). Construction of a sewer extension without this Department's approval will be a violation of this permit.

B. Anticipated Noncompliance. The permittee shall give reasonable advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

14. Reporting Noncompliance

A. The permittee shall report any noncompliance which may endanger health or the environment. The permittee shall provide the Department with the following information:

(1) A description of the discharge;

(2) Steps being taken to determine the cause of noncompliance;

(3) Steps being taken to reduce and eliminate the noncomplying discharge;

(4) The period of noncompliance, including exact dates and times. If the noncompliance has not been corrected, the anticipated time when the discharge will return to compliance;

(5) The cause of the noncompliance; and

(6) Steps being taken to reduce, eliminate, and prevent reoccurence of the noncomplying discharge.

B. The permittee shall orally provide the information in paragraphs A.(1) through (3) to the DEP Hotline (609) 292-7172 within 2 hours from the time the permittee becomes aware of the circumstances.

C. The permittee shall orally provide the information in paragraphs A.(4) through (5) to the DEP Hotline within 24 hours of the time the permittee becomes aware of the circumstances.

D. A written submission shall also be provided within 5 days of the time the permittee becomes aware of the circumstances. The written submission shall contain the information in A.(1) through (6).

E. Other Noncompliance. The permittee shall report all instances of noncompliance not reported under paragraphs 11.J, 11.K, 13.A, and 14.A through D at the time monitoring reports are submitted. The reports shall contain the information required in the written submission listed in paragraph 14.D.

F. The following shall be reported to the Department in accordance with paragraphs 14.A through D:

(1) In the case of any discharge subject to any applicable toxic pollutant effluent standard under Section 307(a) of the Federal Act or under Section 6 of the State Act the information required by paragraphs 14.A(1) through (3) regarding a violation of such standard shall be provided to the Department within 2 hours from the time the permittee becomes aware of the circumstances. The information required by paragraphs 14.A(4) through (6) shall be provided to the Department within 24 hours from the time the permittee becomes aware of the circumstances. Where the information is provided orally, a written submission covering these points must be provided within five working days of the time the permittee becomes aware of the circumstances covered by this paragraph.

(2) In the case of other discharges which could constitute a threat to human health, welfare, or the environment, including but not limited to, discharge of pollutants designated under Section 311 of the Federal Act, under Section 6 of the State Act, under the "Spill Compensation and Control Act", N.J.S.A. 58:10-23.11 et seq., or under the "Safe Drinking Water Act", N.J.S.A. 58:12A-1 et seq., the information required by paragraph 14.A(1) through (3) shall be provided to the Department within 2 hours from the time the permittee becomes aware of the circumstances. The information required by paragraphs 14.A(4) through (6) shall be provided to the Department within 24 hours from the time the permittee becomes aware of the circumstances. Where the information is provided orally, a written submission covering these points must be provided within five working days of the time the permittee becomes aware of the circumstances covered by this paragraph.

(3) The information required in paragraphs 14.A(1) through (3) shall be provided to the Department within 2 hours where a discharge described under paragraphs 14.F(1) or (2) is located upstream of a potable water intake or well field. The information required by paragraphs 14.A(4) through (6) shall be provided to the Department within 24 hours. If this information is provided orally, a written submission covering these points must be provided within five days of the time the permittee becomes aware of the discharge.

(4) Any bypass which violates any effluent limitations in the permit shall be reported within 24 hours unless paragraphs 14.F(1) through (3) are applicable. (See Section 15.)

(5) Any upset which <u>violates</u> any effluent limitation in the permit shall be reported within 24 hours unless paragraphs 14.F(1) through (3) are applicable. (See Section 16.)

(6) Violation of a maximum daily discharge limitation for any of the pollutants listed by the Department in the permit shall be reported within 24 hours unless paragraphs 14.F(1) through (3) are applicable (See N.J.A.C. 7:14A-3.13(a)7.).

15. <u>Bypass</u>

A. <u>Bypass not exceeding limitations</u>. The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it is also for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of paragraphs B. and C. of this section.

B. <u>Notice</u>

(1) <u>Anticipated Bypass</u>. If the permittee knows in advance of the need for a bypass, he shall submit prior notice, if possible, at least thirty (30) days before the date of the bypass.

(2) <u>Unanticipated Bypass</u>. The permittee shall submit notice of an unanticipated bypass as required in paragraph 14.F.(4).

C. <u>Prohibition of Bypass</u>

(1) Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass unless:

a. Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

b. There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if the permittee could have installed adequate backup equipment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and

c. The permittee submitted notices as required under paragraph B of this section.

(2) The Department may approve an anticipated bypass, after considering its adverse effects, if the Department determines that it will meet the three conditions listed above in paragraph C.(1) of this section.

16. <u>Upset</u>

A. <u>Effect of An Upset</u>. An upset may constitute an affirmative defense to an action brought for noncompliance with such technology-based permit effluent limitations if the requirements of paragraph B. of this section are met. Where no determination was made during administrative review of claims that noncompliance was caused by upset, and there has been no Departmental action for noncompliance, the lack of such determination is final administrative action subject to judicial review.

B. <u>Conditions Necessary for A Demonstration of Upset</u>. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs, or other relevant evidence that:

RECEIVED
MAY 5 1989
Dept. Environmental Protection
Division Water Resources
Bureau of Ground Water Quality Mgt.

Let's protect our earth

State of New Jersey

DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF WATER RESOURCES
METRO BUREAU OF REGIONAL ENFORCEMENT
2 BABCOCK PLACE
WEST ORANGE, NEW JERSEY 07052

GEORGE G. McCANN, P.E.
DIRECTOR

DIRK C. HOFMAN, P.E.
DEPUTY DIRECTOR

May 1, 1989

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Ronald Pope
Manager of Environmental Affairs
Elizabethtown Gas Company
One Brown Plaza
Iselin, New Jersey 08830-9990

Dear Mr. Pope:

On May 28, 1986, the consulting firm of Dames & Moore, on behalf of Elizabethtown Gas Company (EGC), submitted a request to this Department (NJDEP) for an emergency New Jersey Pollutant Discharge Elimination System (NJPDES) permit for performing short-term pumping tests on four monitoring wells. In this request it was revealed that chemical analysis of ground water samples collected from the four monitor wells reported the presence of base/neutral compounds (at concentrations ranging to 3700 ppb), volatile organic compounds (at concentrations of 500 ppb), and cyanide (at a concentration of .4 ppm). It was also revealed that three inches of oily material was observed on the surface of monitor well no. 5.

These results demonstrate the need for further investigation of the contamination upon the ground water. Pursuant to the New Jersey Water Pollution Control Act, N.J.S.A. 58:10A-6.1 et seq., and the regulations promulgated pursuant thereto, N.J.A.C. 7:14A-1 et seq., all discharges, past or present, actual or potential, to the ground water or onto land which might flow or drain into the waters of the State is an activity governed under the New Jersey Pollutant Discharge Elimination System (NJPDES) regulations. The purpose of this requirement is to establish the presence of ground water pollutant plumes which may exist at a facility.

Implementation of the NJPDES requirements are the enforcement mechanism by which discharges are brought into conformance and compliance with laws, regulations, and standards. Therefore, in order for EGC to achieve compliance with the aforementioned regulations, EGC is directed to apply for a standard NJPDES/ Discharge to Ground Water (DGW) permit within thirty (30) calendar days of receipt of this directive. NJPDES/DGW permit application forms can be obtained by contacting:

New Jersey Department of Environmental Protection
Division of Water Resources
Bureau of Information Systems
CN-029
Trenton, New Jersey 08625
(609) 984-4425

Any questions concerning the completion of the Discharge to Ground Water permit application should be addressed to the Bureau of Ground Water Discharge Control staff, who may be reached at (609) 292-0424. The completed application must be sent to the Bureau of Information Systems. A copy of the cover letter accompanying this application shall also be submitted to this office.

It is anticipated that EGC will cooperate with the Department in this matter. However, failure to comply with this directive will result in appropriate enforcement action including the imposition of penalties for non-compliance.

If there are any questions concerning this matter please call Howard S. Goldman, the Environmental Specialist responsible for this case, who can be reached at (201) 669-3900.

Very truly yours,

Gloria T. Grant

Gloria T. Grant
Supervisor
Ground Water Unit
Metro Bureau of Regional Enforcement

E20

c. Ted Hayes, BGWDC
Joseph Krulik, BGWPA
Kenneth Sandor, H.O.

FACT SHEET
FOR THE NJPDES PERMIT TO DISCHARGE
INTO THE GROUND WATERS OF THE STATE

Name and Address of Applicant:

Elizabethtown Gas Company
One Brown Plaza
Iselin, NJ 08830-9990

Name and Address of Facility Where Discharge Occurs:

Elizabethtown Gas Company
Third Avenue and Florida Street
Lot No. 1381, Block No. 5
Elizabeth, NJ 07206

Receiving Water:

Ground Waters of the State. The site is underlain by the Triassic Brunswick Formation.

Description of Facility:

The site is a propane, liquified natural gas (LNG), and natural gas storage and transfer (rail, truck, and pipeline) facility. Aquifer testing will be performed by utilizing four of ten monitoring wells. Water will be recharged by infiltration through diked areas of the crushed stone surface. All wells at the site will be sampled for base/neutral compounds, volatile organic compounds, cyanide, chromium, lead, and petroleum hydrocarbons before the test.

Description of Discharge:

Between 2400 to 7200 gallons (10 to 15 gallons per minute (gpm) at one to two hours, estimated) of pumped ground water. The water (tested in 1984 over Ground Water Quality Standards for base/neutral compounds, volatile organic compounds, and cyanide) is to be pumped and recharged to the ground as part of an aquifer characterization test. Permit limits maximum discharge to 25,000 gallons.

Permit Conditions:

According to the attached General and Specific Conditions.

NJPDES No. for Emergency Permit

NJ0063746

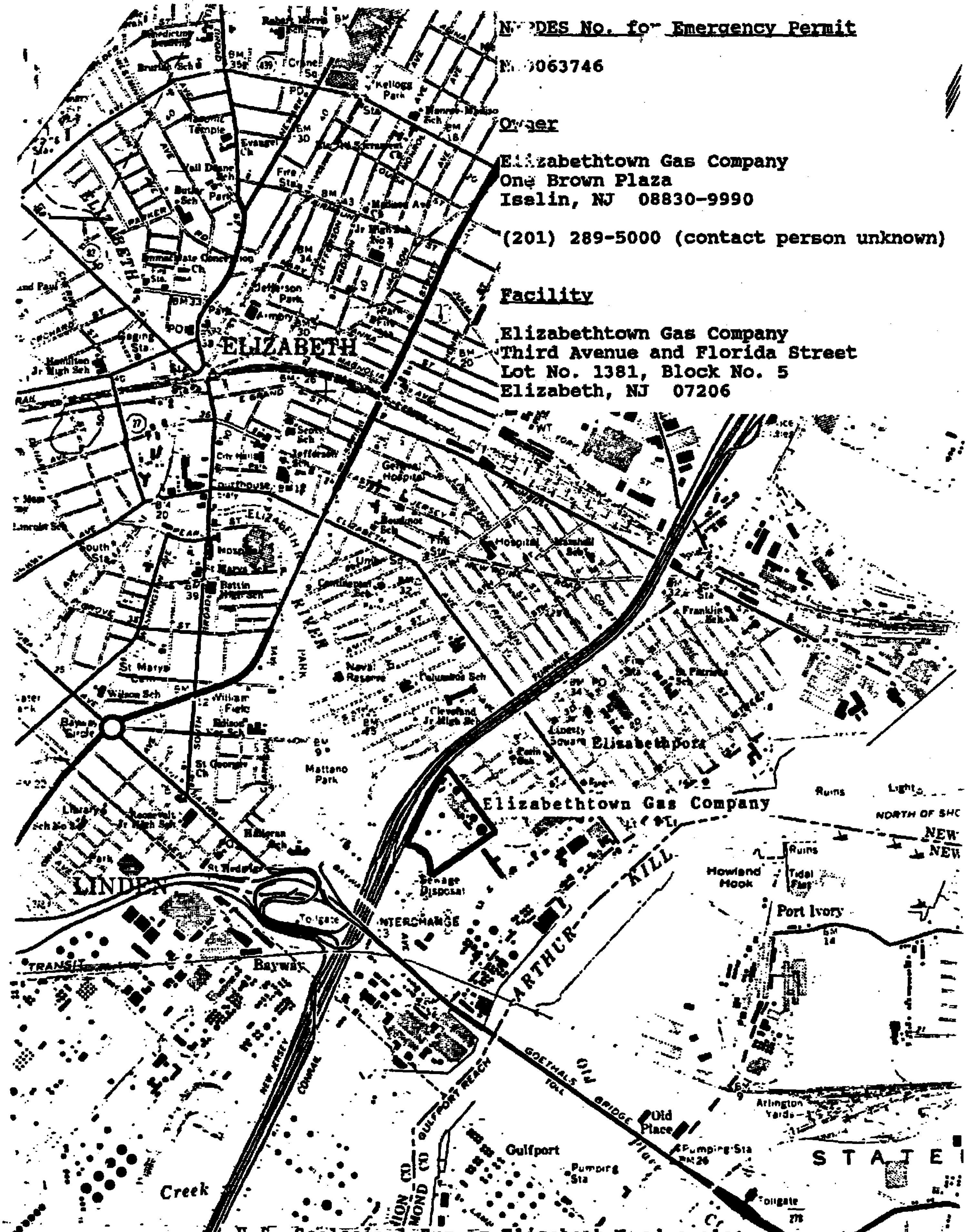
Owner

Elizabethtown Gas Company
One Brown Plaza
Iselin, NJ 08830-9990

(201) 289-5000 (contact person unknown)

Facility

Elizabethtown Gas Company
Third Avenue and Florida Street
Lot No. 1381, Block No. 5
Elizabeth, NJ 07206



U.S. Geological Survey Elizabeth Quadrangle

njpdes	facname	facstreet	faccity	faczip	facenfrg	facmaj
NJ0002101	COMPRESSOR STATION 240 LGN PLT	718 PATERSON PLANK ROAD	CARLSTADT	07072	NE	MI
NJ0002798	HENKEL CORPORATION	BERRY AVE AT RT 17 NORTH	CARLSTADT	07072	NE	MI
NJ0003344	YOO-HOO BEVERAGE CORPORATION	600 COMMERCIAL AVENUE	CARLSTADT	07072	NE	MI
NJ0003719	METAL IMPROVEMENT CO INC	472 BARELL AVE	CARLSTADT	07072	NE	MI
NJ0005754	TECHNICAL OIL PRODUCTS CO INC	150 GRAND STREET	CARLSTADT	07072	NE	MA
NJ0028991	RANDOLPH PRODUCTS CO INC	PARK PLACE EAST	CARLSTADT	07072	NE	MI
NJ0029378	GROBET FILE CO OF AMERICA INC	750 WASHINGTON AVENUE	CARLSTADT	07072	NE	MI
NJ0030970	ARSYNCO INC	FOOT OF 13TH ST	CARLSTADT	07072	NE	MA
NJ0030996	GENERAL AUTOMOTIVE SPEC CO INC	462 BARELL AVENUE	CARLSTADT	07070	NE	MI
NJ0032522	COSAN CHEMICAL CORP	400 14TH STREET	CARLSTADT	07072	NE	MI
NJ0032590	SPEAR PACKING CORPORATION	95 BROAD STREET	CARLSTADT	07072	NE	MI
NJ0033405	TEC CAST INC	440 MEADOW LANE	CARLSTADT	07072	NE	MI
NJ0050300	ALFA INK DIV/LAKELAND LAB INC	655 WASHINGTON AVENUE	CARLSTADT	07072	NE	MI
NJ0052370	STANBEE CO., INC	70 BROAD STREET	CARLSTADT	07072	NE	MI
NJ0052728	NOVUS FINE CHEMICALS LLC	611-641 BROAD ST	CARLSTADT	07072	NE	MI
NJ0053121	TOWN OFFSET DIV STERLING REGAL	75 BROAD STREET	CARLSTADT	07072	NE	MI
NJ0055948	MORRIS PARK AVE CLAY PIT	100 AMOR AVENUE	CARLSTADT	07072	NE	MI
NJ0078310	YELLOW FREIGHT SYSTEMS INC	NORTH BERGEN TERMINAL	CARLSTADT	07072	NE	
NJ0081779	NEW YORK TIME CARLSTADT FAC	600 WASHINGTON AVENUE	CARLSTADT	07072	NE	
NJ0089303	ARSYNCO INC	FOOT OF 13TH ST	CARLSTADT	07072	NE	MA
NJ0101958	ARSYNCO INC	FOOT OF 13TH ST	CARLSTADT	07072	NE	MA
NJ0104591	NOVUS FINE CHEMICALS LLC	611-641 BROAD ST	CARLSTADT	07072	NE	MI
NJ0106640	ROADWAY EXPRESS INC.	700 COMMERCIAL AVE.	CARLSTADT	07072	NE	
NJ0107697	YOO-HOO BEVERAGE CORPORATION	600 COMMERCIAL AVENUE	CARLSTADT	07072	NE	MI
NJ0110973	PROSPECT TRANSPORTATION	583 INDUSTRIAL ROAD	CARLSTADT	07072	NE	
NJ0111058	GENERAL FOAM CORP	109 KERO ROAD	CARLSTADT	07072	NE	
NJ0111236	RECKITT & COLMAN INCORPORATED	179 COMMERCE ROAD	CARLSTADT	07072	NE	
NJ0111287	POTTERS INDUSTRIES INCORPORATE	600 INDUSTRIAL ROAD	CARLSTADT	07072	NE	
NJ0111805	CITROL AROMATIC	320 VETERANS BLVD	CARLSTADT	07072	NE	
NJ0111830	KROHN INDUSTRIES INC	303 VETERANS BLVD	CARLSTADT	07072	NE	
NJ0111953	MANHATTAN PRODUCTS INC	333 STARKE ROAD	CARLSTADT	07072	NE	
NJ0112364	CARRETTA TRUCKING INC	130 MOONACHIE AVENUE	CARLSTADT	07072	NE	
NJ0112879	BILLINGS FREIGHT SYSTEMS INC	256 PATERSON PLANK ROAD	CARLSTADT	07072	NE	
NJ0113298	SEAGRAVE COATINGS CORPORATION	320 PATERSON PLANK RD	CARLSTADT	07072	NE	
NJ0113310	COOK & DUNN PAINT CORP	700 GOTHAM PKWY	CARLSTADT	07072	NE	
NJ0113492	HARTIN PAINT	225 BROAD STREET	CARLSTADT	07072	NE	

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PRELIMINARY SITE INVESTIGATION
ERIE STREET SITE
ELIZABETHTOWN GAS CO.
ELIZABETH, NEW JERSEY

FEBRUARY 23, 1989
JOB NO. 13740-003-10

DAMES & MOORE

CRANFORD, NEW JERSEY

1.0 INTRODUCTION

We are pleased to submit this report on an Environmental Investigation performed at Elizabethtown Gas Company's Erie Street site (Figure 1) in accordance with the contract dated August 21, 1984 for P.O. 841951. The purpose and scope of services were developed in meetings held between representatives of Dames & Moore and Elizabethtown Gas Co. The focus of the investigation was evaluations of soil and ground water conditions and assessments of soil and water quality to evaluate the extent of coal gasification by-products, if any, buried on site. These materials include:

- wood chips — used in the purification process in coal gas manufacturing;
- coal tar — produced as a by-product of coal gas manufacturing; and
- other liquid materials.

Since coal gas is no longer produced or handled on-site, these materials are no longer produced or disposed of on-site.

2.0 PURPOSE

The purposes of this investigation are to:

1. assess the geologic and hydrologic conditions on-site; and
2. evaluate the vertical and lateral extent of soil and ground water contaminants, if present.

3.0 SCOPE OF SERVICES

The scope of services included:

1. review of existing data;
2. drilling exploratory borings and monitor wells;
3. measurement of water levels and water level fluctuations;
4. logging of soil properties and visibly contaminated soil zones;
5. preparation of maps, cross sections and charts depicting site conditions;
6. TV logging of monitor wells;
7. cleaning and redevelopment of monitor wells; and
8. water sampling for visual inspection and chemical analysis;
9. report preparation.

4.0 REGIONAL SETTING

The Erie Street facility is located in Elizabeth, Union County, New Jersey (Figure 1). Union County lies within the Piedmont Plateau physiographic province.

The province is characterized as a region of low lying plains and gently sloping hills with occasional basalt ridges. Altitudes range from approximately 550 feet along the Watchung basalt ridges to sea level at the Arthur Kill near the site area. Topography and surficial features are primarily the result of Quaternary glacial events which both scoured the existing bedrock surfaces and deposited a mantle of drift in the region. Drift comprises stratified and non-stratified tills, and fluvial and lacustrine deposits. In the Elizabeth area, the glacial deposits are reported to be primarily ground moraine deposits (till which was deposited from below the glaciers as the ice retreated). Bedrock underlying the site consists of the Triassic Brunswick Formation. The Brunswick formation consists of soft red shales and sandstones and serves as the most important aquifer in the county. However, no public supply well fields tapping the bedrock are reported in the City of Elizabeth. Reportedly, Valley fill deposits (glacial soils and gravels which accumulated in ancient bedrock valleys) serve as additional sources of ground water in the county. Several drainage basins are located in Union County. The site lies within the Elizabeth River basin which encompasses the majority of Elizabeth.

5.0 SITE BACKGROUND

The site is an active propane, natural gas, and LNG storage and transfer facility covering approximately 20 acres. It is bounded on the north by Third Avenue and private residences, on the east by Bilkay's Trucking Company, on the south by the Elizabeth River and on the west by ConRail Railroad tracks and the New Jersey Turnpike (Figure 2). The Erie Street facility is located in a mixed commercial-residential district of Elizabeth along the Elizabeth and Arthur Kill Rivers.

Analysis of air photographs of the site vicinity taken in 1923, 1940, 1959 and 1978 provide insight into demographic and land use alterations which have occurred. Air photos show that the facility appears to have been built on a low-lying marshy area. Drainage channels running southeast, apparently designed to drain the marshy soils, provided drainage pathways to the Elizabeth River. Original buildings and structures were clustered in the northern portion of the site along Third Avenue.

Prior to serving in its present capacity, the facility served as a coal gas manufacturing plant. As part of the gasification processes, coal, coke and slag, coal tars, and wood chips from gas purification were created as by-products. A portion of these materials were landfilled on the site, particularly in the southern areas of the site where they were used with other backfill materials to cover the marsh deposits.

Coal storage piles were observed in air photos from 1923 to be maintained in the west central portion of the site. Additional related materials, including wood chips, coke and slag piles were reportedly maintained in the southern portion of the site. Many of the structures associated with the gasification process have been removed, including the generator and compressor houses, tar separators and gas holders in the north and northwest portions of the site.

The present Elizabeth River Channel location has been modified by the U.S. Army Corps of Engineers as part of its flood control program. The channel has been straightened to run approximately east-west along the site. Previously the river channel curved to the south. Dredge spoil from this effort was probably used as fill material to cover marsh deposits along the river and to construct flood control embankments along the river. The embankments lie along the site's southern boundary. Water gates in the flood control embankments allow surface water to drain from the site into the river during low tides and prevent river water from entering the site during high tides. During high tides, a pump discharges runoff water into the river.

6.0 PREVIOUS INVESTIGATIONS

Several geotechnical and environmental investigations have been completed for the Erie Street plant. Those reviewed by Dames & Moore as part of this investigation include Draft Environmental Impact Statement, Proposed Propane Air Peakshaving Facilities, 1973, by Edwards and Kelcey, Inc.; several engineering soils reports by Geotech Associates; Analysis of Soil Sample for Elizabethtown Gas Co. by E. I DuPont de Nemours and Co., Inc.; and several environmental reports prepared by Transcontec, Inc. concerning soil and water samples collected at the facility.

Geotechnical investigations reported stratigraphic conditions similar to those identified by Dames & Moore: fill overlying organic soils or clays overlying bedrock with ground water usually observed in the upper five feet of soil (see Section 8).

The DuPont report contained analysis by GC/MS of a single soil sample obtained from an unknown location. The analysis indicated the presence of naphthalene and isomers of methyl naphthalene which are constituents of coal tars.

Three reports dated December 17, 1983, January 16, 1984 and September 18, 1984, prepared by Transcontec, were reviewed. The December 17, 1983 report presents results of analyses of soil samples collected at random and analyzed as part of an initial investigation which compared site conditions to estimated background conditions. The six soil and ground water samples were analyzed for metals, sulfate, phenols, cyanide, pH and oil and grease. The locations of the sampling points are not provided. The report concludes that the metal concentrations are near to expected background levels. The pH tends to be acidic.

The January 16, 1984 report presents results of analyses of soil and water samples collected during the installation of the plant's fire protection system on October 31, 1983. Samples were analyzed to assess residual compounds in selected areas of excavation. Nine soil samples and one ground water sample were collected by Transcontec for analysis during the construction of the fire control system. The air in the head space of each soil sample jar was analyzed. Aromatic hydrocarbon vapor, including benzene, toluene and/or xylene, were detected in the head space air of seven soil samples. The approximate locations of the soil samples are shown in Figure 2. Results of additional analyses, if any, have not been made available.

The September 18, 1984 report presents results of analyses of eight water samples collected July 13, 1984 from the Elizabeth River and storm water drain. This report was initiated to evaluate water upgradient and downgradient of the plant and in the storm water drain. Four water samples were collected in the drain and four water samples were collected in the river at locations along the facility's southern boundary. The water samples collected on July 13, 1984 are reported to contain both aromatic and aliphatic hydrocarbons derived from either kerosene, heating oil, naphthas, coal liquids or motor oil. The westernmost samples were collected near the railroad crossing and additional samples collected downstream. The river sample collected near the railroad crossing did not contain hydrocarbons. The sample collected near the storm water outfall contained aliphatic and aromatic hydrocarbons. Two samples were collected further to the east in the river. One sample contained no detectable hydrocarbons and the other contained only a trace of hydrocarbons. The water sample collected from the drain near the central portion of the property's southern boundary contained hydrocarbons whereas samples collected both upstream and downstream in the drain contained only traces or no detectable hydrocarbons. Since no hydrocarbons were detected in water samples obtained furthest downgradient in the drain and river, preliminary evaluation provided in the report indicates that little hydrocarbons were leaving the Elizabethtown Gas Co. facility.

These preliminary studies report that residual hydrocarbons were present in soils at specific locations on site and that surface water in the storm water drain and the Elizabeth River contained trace levels of residual hydrocarbons.

7.0 SITE INVESTIGATION

7.1 GENERAL

A comprehensive site investigation program has been carried out at the site since 1984. The program has included the following:

- performing several site inspections
- drilling 19 soil borings
- installing 10 overburden aquifer monitoring wells
- installing three bedrock aquifer monitoring wells
- surveying well elevations and locations
- obtaining ground water samples for analysis
- obtaining soil samples for analysis
- monitoring water level elevations
- installing water level recorders in each well
- performing downhole TV inspection of well screen
- cleaning and redeveloping wells
- observing well performance data during well purging.

Nineteen (19) soil borings were made throughout the site under the observation of Dames & Moore. Locations of the borings are shown in Figure 2. Thirteen (13) borings were converted into monitor wells. Ten (10) of the wells are screened in the shallow alluvial material. Three wells are screened (open holes) in the bedrock underlying the alluvial soil. The deep wells are arranged in pairs with adjoining shallow wells in order to evaluate the relative hydraulic head in the two aquifer zones. Locations of the monitor wells are shown in Figure 2.

Elevations of the well casings and ground surface elevations of borehole locations were surveyed by a licensed land surveyor. Water level measurements were made in all wells in order to prepare a water level contour map of the site. Water level recorders were set up on all wells (both shallow and deep) to evaluate the effects of tidal fluctuation on the ground water levels.

Water samples were collected from all wells and sent to Environmental Testing & Certification (ETC) for chemical analysis. Four ground water samples were analyzed for full priority pollutants with plus 40 library search. Remaining samples were analyzed for priority pollutant base/neutral compounds. In addition, water samples were collected from the water surface of each well to observe if any floating contaminants were visually present. Water samples were also collected from the bottom of each well to observe if dense, separate phase contaminants were visually present. Soil/waste samples were collected from three selected borings and analyzed.

7.2 TV INSPECTION OF WELLS

Because of the presence of coal tar residues in the soil at the site, a question was raised regarding possible detrimental effects of coal tar on the PVC well screens used for construction of the monitor wells. Therefore, a decision was made to inspect the condition of the monitor wells with a down-the-hole television (TV) camera. For this purpose, Graham Every Artesian Well Co. of Rochelle, New Jersey was contracted to do the TV logging of the monitor wells.

Prior to TV logging of the monitor wells, each well was checked for the presence of floating oil. A thin sheen of oil was observed floating in Wells MW-5 and MW-6. This oil was removed by swabbing with oil adsorbent material on March 7, 1986, just prior to the TV logging of the wells. The floating oil was cleaned out to prevent blurring of the TV camera lens. A permanent record of the TV logs of the monitor wells was made on a VHS video cassette. TV logging of the wells was conducted on March 10, 1986.

As a result of the TV survey of the monitor wells, Dames & Moore recommended that the monitor wells should be cleaned and redeveloped prior to any pump testing of the wells.

7.3 WELL CLEANING AND REDEVELOPMENT

On May 1 and 2, 1986, each of the monitor wells was cleaned and redeveloped. Each monitor well casing and screen was cleaned by brushing with a 4-inch diameter brush (similar to a bottle brush) mounted on the end of a metal rod. After each well was brushed, the loose debris was removed from the well by pumping and surging the well until the discharge water ran clean. About an hour was spent cleaning each well.

7.4 SPECIFIC CAPACITY OF MONITOR WELLS

While each monitor well was being pumped after the brushing action was completed, drawdown measurements were made in the well. The pumping rate was also measured while the water was being pumped from the well. In this manner, the specific capacity of each well was estimated. The specific capacity of a well is defined as the pumping rate divided by the drawdown in the well. The drawdown generally increases with the length of time that a well is pumped at a constant rate. Therefore, to compare the specific capacity of several wells for short pumping periods, the specific capacity should be specified for the same pumping time period for each well.

8.0 RESULTS

8.1 STRATIGRAPHY

The various layers of earth materials encountered at the site from youngest to oldest (top to bottom) consist of:

Fill
Peat
Residual Soils
Bedrock

Each of these units are described below:

Fill

The entire site is covered by a layer of fill ranging from one to 10 feet thick except in one localized area where a 30-foot thick zone was observed while drilling well MW-2. This thickness of fill is related to an excavation for a tank which is no longer in existence. The fill generally increases in thickness southward toward the Elizabeth River. Photos of the site show that the southern part of the site near the river was once swampland and thus topographically lower than the northern part of the site.

The fill is generally composed of silty sand and gravel with some areas containing silt and clay, cinders, coke and slag and wood chips. Coal tars are found in the coke and slag. Cinders are often found with oil and/or an oily odor.

There is a significant difference in the character of the fill between the northern and southern halves of the site. The northern fill consists primarily of cinders about one to three feet thick except at the 30-foot tank excavation. At the tank excavation, fill consists of sand, clay and gravel with substantial quantities of rubble, primarily wood beams. This northern fill generally is not oil saturated and overlies natural clay soils. An exception is noted at the tank excavation where the fill was visibly contaminated with oil and is believed to be directly in contact with the bedrock. The southern fill is thicker, up to 10 feet, and contains cinders, debris, coke, slag, wood chips and is often oil saturated. This fill overlies peat and organic silts and clays.

Peat

Green and yellow peat with organic silts and clays is found underlying the southern two-thirds of the property. The peat is a maximum of five to six feet thick on the southern border and pinches out northward. The peat is saturated with water and is very soft with a very low blow count. Fill material consisting of slag and coke has penetrated the upper part of the peat due to settling of the slag.

Residual Soils

Natural soils which are probably residual soils and till formed on the bedrock, underlie the fill and peat deposits over all of the site. These soils consist of red brown clays and silty clayey sands. These soils range from 5 to 17 feet thick.

Gravel

A thin gravel zone about 1 to 2-feet thick overlies the bedrock along the southern edge of the property. This is probably a fluvial deposit related to the Elizabeth River.

Bedrock

The bedrock consists of Triassic Brunswick shale with occasional fractures and clay seams. The depth to bedrock established by borings and wells in this investigation ranges from 14 to 31 feet. In general, the depth to bedrock decreases in an easterly direction across the site.

Cross Sections

Several cross sections have been drawn which show the interpreted relationship of the various stratigraphic units described at the site. Locations of the cross sections are indicated in Figure 2. Cross sections are shown in Figure 3. Logs of borings and monitor well details are contained in the Appendix.

8.2 TV INSPECTION OF WELLS

The TV logs revealed that there was no visible damage done to the PVC well screens as a result of coal tar residues in the soil. Wells MW-5 and MW-6 were the only wells to contain any visible oil floating on the water in the well. Well MW-5 also had some heavy oily material in the bottom of the well.

The monitor wells generally contained mineral deposits on the interior of the wells in the form of small hair-like protrusions about 1 to 2 mm long, extending inward from the screen slots. These deposits were loosely attached to the PVC well screen slots and tended to break loose as a result of the passage of the TV camera through the well water, thereby making the water turbid.

Wells MW-7 and MW-9 contained turbid water, and therefore the condition of the PVC screens could not be observed with the TV camera.

8.3 GROUND WATER HYDROLOGY

There appear to be two separate aquifer zones underlying the site. One aquifer exists within the unconsolidated surficial soils and the other is within the underlying bedrock. The soil aquifer zone appears to be separated from the bedrock aquifer zone by a zone of low permeability composed of the silty clay described above.

The water table in the soil aquifer zone ranges from about 2.5 to 7.5 feet below the ground surface. In most locations, the water table is within the fill layer. The slope of the water table and direction of ground water flow vary throughout the site. In general, the ground water flow diverges to the southeast, east, and north away from the central part of the site's western boundary.

The ground water flow paths can be visualized by examining the water table contour map in Figures 4 and 7 containing data from September 1984 and October 1986, respectively. The highest water table elevation at the 1984 readings is 5.66 feet at well MW-4 on the west side of the site and the lowest is 2.93 feet at well MW-7 in the southeast corner of the site. Ground water elevations measured from each monitor well for several dates are shown in Table 1. Ground water flows from zones of high elevation head to zones of low elevation head along paths which are perpendicular to the water table elevation contour lines. A few representative flow lines have been drawn on Figure 4. It can be seen that ground water underflow enters the property on the west boundary in the vicinity of well MW-4 and flows radially away from this location throughout the site. Most of the ground water flow is toward the north side of the site in the vicinity of well MW-2, which is situated in the 30-foot deep backfilled excavation. This flow path represents the most permeable ground water zone on-site.

Ground water flow to the south toward the river is restricted because of the peat and silty clay deposits along the southern part of the property. Ground water flow is restricted to the northeast because of the thick clay there as shown by well MW-3.

Ground water flow and quality to the north and east may be affected by the presence of leaky sewers along Third Avenue and South Second Street. Storm and sanitary sewers commonly leak at the joints, especially in older urban areas. The depth of the water table is in the range of 3 to 6 feet below grade which puts it at or above the invert elevations of most urban sewer lines.

In order to investigate the tidal response in the aquifers on-site, water level recorders were initially installed in a pair of wells near the river, which exhibits tidal fluctuations on the order of about 2 feet. It was found that tidal response of water levels in the soil aquifer are negligible. A continuous water level recorder was installed in well 5, which is about 50 feet from the edge of the river, and a tidal response of about 0.05 foot was observed. This compares to the 0.5 foot tidal response in a bedrock well (MW-5D) at the same location. The very small tidal response in the soil aquifer is primarily the result of a relatively large storage coefficient in the soil aquifer, which is an unconfined water table aquifer. A low permeability caused by silts and clays in the aquifer matrix in some areas could also tend to reduce the tidal response.

In order to verify these findings, water level recorders were subsequently installed on the remaining monitor wells. Generally, the same tidal responses were observed: bedrock wells show 0.25 to 0.5 foot response and soil wells show almost no response. Well MW-1, screened in the overburden, however, showed eratic but cyclical changes in water level, which correlated well with similar changes observed bedrock in well MW-1D. This indicates that at this location or very close to this location (northwest corner of site), the bedrock and soil aquifer are in better hydraulic connection than at other locations where well couplets were installed. Graphical descriptions of the water level fluctuations are presented in the Appendix.

There is a significant difference in permeability of the soil aquifer throughout the site as indicated by the response of the soil monitor wells to pumping. Wells in the gravel zone on the southwest side (wells MW-5 and MW-6) are more productive, yielding in excess of 5 gpm. The other soil wells yield less than 5 gpm.

Specific capacities of all overburden wells were estimated. The specific capacity of a well is defined as pumping rate per water level drawdown. Specific capacity is related to the efficiency of the well and to the transmissivity of the aquifer. Therefore, for a set of wells constructed in the same manner and developed to similar degrees of efficiency, variations in the specific capacity are primarily related to variations in the transmissivity of the aquifer. Thus for wells having similar construction details, wells with high specific capacity indicate aquifer zones of high transmissivity, whereas wells with low specific capacity indicate aquifer zones of low transmissivity.

The specific capacities of the monitor wells are listed in Table 5. The measured values of specific capacity range from 0.12 to 200 gpm/ftdd (gallons per minute per foot of water level drawdown). Monitor Well MW-4 has a very high specific capacity, which is significantly higher than the values for any of the other wells on site. When MW-4 was being pumped at a rate of 10 gpm during the cleaning operation, the drawdown stabilized at 0.05 foot. Several of the wells, MW-2, MW-3, MW-7 and MW-8, had such low yields that the wells were pumped dry in less than 10 minutes.

The extremely low specific capacities of these four wells (MW-2, MW-3, MW-7 and MW-8) is consistent with the fact that they are screened in sediments which are composed primarily of silts and clays which are of low permeability. The remaining wells are screened in coarser-grained materials of greater permeability.

The extremely high specific capacity of overburden well MW-4 indicates a zone of very high permeability surrounding the well.

The permeability of the bedrock aquifer is variable, depending upon the number of fractures existing in different locations, as evidenced by the water-yielding capacities of the wells. The bedrock wells on the west side of the site yielded about 35 to 50 pgm (MW-1D and MW-5D). The deep well in the southeast corner (MW-7D) yielded about 2 gpm.

Ground water in the bedrock aquifer exists under confined artesian conditions. The piezometric surface for the bedrock aquifer is similar to the elevation of the water table aquifer. The bedrock aquifer shows a significant tidal response of about 0.5 foot. Therefore, for part of the time, the bedrock aquifer's piezometric water level is higher than the soil aquifer water level and for the rest of the cycle, it is lower than the soil aquifer water level. For this reason, it is difficult to determine if the net vertical gradient is upward or downward at some locations without a continuous record of water levels at all well pairs.

Based upon the water level hydrographs in the appendix, which were made at the end of 1984, the following estimates were made of the average water level elevations in the bedrock aquifer relative to the overlying alluvial aquifer:

Monitor Well	Estimated Average Water Level Elevation (feet)	Estimated Average Vertical Hydraulic Gradient
MW-1	3.8	Down
MW-1D	3.0	
MW-5	3.2	Up
MW-5D	3.3	
MW-7	2.9	Down
MW-7D	0.7	

These data suggest that the net average gradient is from the shallow alluvial aquifer to the bedrock aquifer for much or most of the site. Whereas the estimated gradient is upward at MW-5 and MW-5D, the difference in average water level is relatively small. Therefore, the net upward flow of ground water from the bedrock to the alluvial aquifer at this location could be relatively small. At the other locations, the estimated gradient is strongly downward. At MW-1 and MW-1D, the estimated difference in water level elevation is 0.8 foot. At MW-7 and MW-7D, the estimated difference is 2.2 feet. Therefore, downward flow of ground water at these locations could be significant if a permeable pathway exists to allow the water flow to respond to the gradient. Because shallow monitor well MW-1 responds strongly to the tidal response along with MW-1D, this suggests that there is a good hydraulic connection between MW-1 and MW-1D somewhere near this well pair. Such a connection could be natural, such as if the intervening clay layer is missing, or be the result of man's activity, if man-made excavations penetrated through the clay layer and were backfilled with permeable fill.

8.4 HYDROGRAPH OF WELL MW-4

The initially highest water table elevation recorded on the site is at MW-4 (see Figure 4). Flow net analysis of the water table elevation contours indicates that much of the ground water in the water table aquifer at the site originates as underflow from the adjacent property west of the site, rather than from direct infiltration of precipitation on the site. The factors which support this observation include:

1. Ground water flow lines for the entire site diverge from a relatively small zone around MW-4, indicating the small zone is the primary area of recharge to the aquifer. This zone is interpreted to extend beyond the property boundary;

2. Very high specific capacity is observed at MW-4 (210) and high specific capacity is observed for nearby downgradient wells MW-10 (33.3), MW-6 (45.5) and MW-5 (14.3). This indicates that soils in these areas of the facility near the adjacent property are zones of higher permeability which allow for underflow from adjacent property;

3. Very low hydraulic gradient between MW-4 and MW-10 indicates little restriction to flow (i.e., greater permeability) in the area between these two wells;

4. Wet areas and ponded water observed in depressions along the railroad tracks receive runoff from the turnpike and serve as a source of ground water recharge. Since these areas are usually moist or wet, precipitation need not overcome the soil moisture deficit before percolating to the aquifer (see below);

5. The response of water level in MW-4, screened in more permeable soil, to summer rainfall event is likely the result from rain water entering the subsurface from depressions along the railroad tracks and flowing through the zone of higher permeability to MW-4.

It has been hypothesized that the ground water underflow which flows approximately eastward toward MW-4 originates from New Jersey Turnpike runoff or other source, which is recharged west of the site. In order to assist in evaluting the hydrologic regime of the site, a water level hydrograph was made of MW-4 for a period of 21 days using a Stevens water level recorder. The hydrograph is shown on Figure 5. It can be seen that the general trend in the water level is a gradual decline for the 21-day period of record. However, it can be seen that the 0.74-inch (0.062-foot) of rain which fell on September 5, 1986 caused a measurable rise in the water level of the well on the order of 0.25 foot. The response is attributable to conditions described in Nos. 4 and 5 above and in the following paragraphs.

Because of the high evaporation potential during the summer months which causes a moisture deficit in the soil, which is usually not satisfied until October or November, direct recharge of rainfall through the soil horizon generally does not occur until late October or November. During the summer months, the water table elevations generally continue to decline even during periods of summer rainfall events.

The depression between the turnpike and the Conrail property receives runoff from the turnpike. Because the runoff from the impervious surface of part of the turnpike is concentrated in this depression, there is sufficient water accumulation to overcome the soil moisture deficiency during the summertime, thereby allowing water to reach the water table from a small rainfall event during the summertime in this limited area. This may account for the rapid rise in water table elevation observed at MW-4 after rainfall events.

8.5 WATER TABLE FLUCTUATIONS

Water level measurements were made in the monitor wells throughout the site at various times starting on October 17, 1984. The water level elevations are summarized in Table 1. Water levels were recorded in order to evaluate tidal effects and rainfall event effects on ground water levels and flow patterns. Evaluation of these data provide insight on site hydrogeologic characteristics.

The water table elevations for the shallow monitor wells listed in Table 1 are plotted graphically on Figure 6 in order to compare the water level response characteristics of each of the monitor wells. The water table elevation is plotted on the vertical axis and time of measurement is plotted on the horizontal axis. However, it should be noted that the horizontal time axis is not plotted to scale. The graphical increment is similar between each set of readings regardless of the time span between readings.

The water table elevations, as manifested in the monitor wells, fluctuate in response to recharge from rainfall. The water table rises as a result of rainfall recharge saturating soils and percolating to the water table. Water table rises are generally relatively rapid compared to declines which occur between recharge events. In some cases there is a lag period in the time between when a rainfall recharge event occurs and when the water table rises in response to the recharge. These cases include rainfall events which must overcome a soil moisture deficit, water level rises in aquifers of lower permeability and water level rises in aquifer zones far removed from zones of recharge. Water table recessions are generally more gradual between recharge events.

By observing the water table hydrographs on Figure 6, it can be seen that the monitor wells can be divided into two groups based upon their response characteristics. The first group can be called the large response group, and the second group can be called the small response group.

The large response group consists of wells MW-4, MW-9 and MW-10. These wells have shown a relatively large rise in water table elevations from 1984 to 1986. These are located in the zone of relatively high permeability indicated by the low hydraulic gradient in Figure 4.

The small response group consists of wells MW-2, MW-3, MW-5, MW-6, MW-7 and MW-8. These wells have shown a relatively smaller rise in water table elevations from 1984 to 1986. These are located in the zone of relatively lower permeability indicated by the steeper gradients shown on Figure 4.

Monitor well MW-1 shows response characteristics which are intermediate between the two groups described, indicating it is located in a zone of moderate permeability.

It should be noted that the large response-type wells (MW-4, MW-9 and MW-10) are mostly high specific capacity wells, as shown in Table 5, the exception being MW-9. The small response wells are mostly low specific capacity wells as shown in Table 5. This suggests that the response characteristics of the wells are a function of two physical properties:

1. permeability of aquifer, and
2. distance from zone of recharge.

Wells MW-4, MW-9 and MW-10, which are closest to the zone of recharge which is hypothesized to be the underflow from the turnpike, show the largest water level response to recharge. The remaining wells which are farther away from this zone of recharge show smaller responses to recharge.

8.6 WATER TABLE ELEVATION CONTOUR MAP 1986

Figure 7 is a water table elevation contour map for September 11, 1986. This map has the same configuration as the October 17, 1984 water table map shown on Figure 4, except that the water levels generally rose between the two sets of readings. The largest water level rises were in the area of MW-4, MW-10 and MW-9, which had water level rises in excess of 1 foot. The remaining wells had water level rises which were about half a foot or less. Water levels at MW-1 and MW-10 declined by 0.10 and 0.16 foot, respectively, for this time period.

Flow net analysis of the water table contour map shows that the general direction of ground water flow has not changed during the period of observation from October 17, 1984 to September 11, 1986. The ground water flow pattern is still a pattern which shows ground water underflow from the western boundary of the site in the vicinity of Conrail and the turnpike, which then diverges to the north toward Third Avenue, to the east toward South Second Street, and to the south toward the Elizabeth River.

8.7 GROUND WATER FLOW IN BEDROCK

Based on the estimated average bedrock water level elevations given for the three bedrock monitor wells in Section 9.0, an estimated bedrock water level contour map was prepared for the site and shown on Figure 8. Based upon these estimated average measurements, the ground water flow in the bedrock is estimated to flow to the southeast under the site. The zone of discharge for the bedrock aquifer is probably the Elizabeth River.

8.8 HYDRAULIC CONNECTION BETWEEN SURFICIAL AQUIFER AND BEDROCK AQUIFER

An analysis of the ground water flow regimes in the alluvial and bedrock aquifers including the tidal response of the monitor wells MW-1 and MW-1D suggests a significant hydraulic connection between the two aquifers in the vicinity of MW-1 and MW-1D. In order to illustrate such a hypothetical connection between the two aquifers, a generalized cross section was prepared from the vicinity of MW-1 and MW-1D to MW-7 and MW-7D, which is illustrated on Figure 9. In this generalized cross section, it can be seen how ground water from the alluvial aquifer could possibly migrate down into the bedrock aquifer near the northwest edge of the property, join with the bedrock aquifer water, and flow to the southeast through the bedrock aquifer toward the vicinity of MW-7D. From there the water would discharge into the Elizabeth River. Similarly, MW-2 appears to have been drilled in a former gas tank pit which was excavated 15 feet into the bedrock. The pit has been filled with silty, clayey soils and miscellaneous debris which likely limit connection between bedrock and overburden aquifers.

8.9 GROUND WATER AND SOIL QUALITY

8.9.1 General

Oily material was encountered in all borings and wells on-site except in the northwest and northeast corners (wells MW-1 and MW-3). Samples of the fill in these two locations did exhibit a petroleum odor when the borings were made.

The oil is found primarily in the fill from a depth of about three to six feet below the land surface down to the peat, and penetrates about one to two feet into the upper surface of the peat. The deeper peat did not contain visible oil but did exhibit oily odors. The contaminated zone starts at about 0.5 foot above the water table and extends downward into the saturated zone.

Analyses of ground water samples obtained from the monitoring wells indicate that ground water contamination is present beneath most areas of the site. Wells MW-1, MW-3 and MW-8 screened in the overburden aquifer contained trace levels of base neutral compounds (below analytic Method Detection Limits). All other overburden wells contained detectable quantities of these compounds. Base neutral compounds were detected at trace levels in two bedrock aquifer monitoring wells and concentrations above the method detection limit for priority pollutant compounds (volatiles, base/neutral, metals, cyanide, phenolics) were detected in bedrock monitoring well MW-7D.

8.9.2 Soil Quality

Borings which encountered very oily fill include B-1, 2, 3, 7 and 10, MW-2, 4, 7 and 10. The remaining borings had strong odors but were not visibly oil saturated. Based upon these observations, the areas of minimum contamination are the areas of the gas holders in the northeast part of the site, and the northwest corner of the site. Other portions of the site contains fill which appears contaminated with oily material. The locations of borings which encountered fill heavily contaminated with oil are shown on Figure 4.

Areas containing wood chips include boring locations MW-7, MW-7D, B-7 and B-3. Wood chips were observed on the land surface in the southern portion of the site. Three soil/waste matrix samples were collected and sent to Environmental Testing and Certification of Edison, New Jersey for analysis of total priority pollutant content and a "plus 40" scan of additional peaks revealed by GC/MS. The samples designated as B-3, B-7 and B-10 were obtained in the fill from depths of 2 to 4 feet, 4 to 6 feet and 5 to 8 feet below grade, respectively. The locations of the sampling points are shown on Figure 2.

Each soil/waste matrix sample contained elevated concentrations of base-neutral extractable compounds associated with coal tars. These include anthracene, naphthalene, acenaphthenes, acenaphthylene, chrysene, pheneanthrene, fluorine and fluoranthene, which were detected in concentrations in the thousands of parts per billion range. In addition, several volatile organic compounds associated with coal tars were also detected. These included benzene, toluene and ethylbenzene. Sample B-7, which visibly contained a higher proportion of wood chips than the other samples, contained the highest concentration of cyanide and arsenic.

Results of chemical analysis of soil/waste samples are summarized in Table 2.

All base-neutral compounds detected in the soil/waste matrix samples were detected in at least one of the ground water samples with the exception of indeno (1,2,3-c-d), pyrene, dibenzo, anthracene, benzo(ghi) perylene, and benzo (k) fluoranthene. Similarly, all volatiles detected in the soil samples were detected in ground water from wells that were analyzed for volatile organic compounds. The only exception was 1,1,1-trichloroethane, which was detected in the soil but not in ground water. Generally, the concentrations of these compounds were greater in the soil samples than in the water samples. Wells MW-7 and MW-7D, installed in an area which was visibly high in wood chips content, showed high levels of cyanide.

The "plus 40" scan revealed additional compounds probably associated with coal tars. These compounds were tentatively identified but not quantified.

8.9.3 Ground Water Quality

After the wells were constructed they were allowed to equilibrate for several days. The wells were then tested to determine if any separate phase oil had accumulated on the water table or on the bottom of the wells. No separate phase oil was detected in the bottom of any well. A trace of oil or tar globules was detected on the surface of the water table in wells MW-5 and MW-5D. A slight oil sheen was detected on the surface of the water in well MW-2.

Water samples were collected from the monitor wells and analyzed. Water samples from wells MW-2, MW-5, MW-7 and MW-7D were analyzed for total priority pollutant content. Water samples collected from each of the remaining nine monitoring wells were analyzed for the base-neutral fraction of priority pollutants.

8.9.3.1 Alluvial Aquifer

Water samples collected from monitor wells 1, 3 and 8, which are located in the areas of minimum visible contamination (based on observations noted during drilling operations) contained trace levels (below method detection limits, or BMDL) of base-neutral compounds. The remaining soil wells contained total base-neutral content of less than 200 ppb with the exception of well MW-4, which showed a total base-neutral content of approximately 23,700 ppb. Generally, those compounds detected in any one well water sample were noted in the majority of the others. The compounds are those associated with coal tar with the exception of a plasticizer (di-N-Butyl phthalate) detected at trace levels in several of the wells.

Each of the three soil wells sampled for total priority pollutants showed some degree of volatile organic contamination. Benzene was detected in all three wells at concentration levels ranging between 529 and 785 ppb. Toluene was also detected in each well in lower concentrations than benzene. Cyanide was identified in all three shallow wells. Oily materials occasionally have been observed at low tide to seep from the alluvial aquifer along the adjacent Elizabeth River and into a surface water drain which is situated along the southern boundary of the property and which also discharges into the river.

Soil well MW-1 and bedrock well MW-1D, which are believed to be placed in an area of hydraulic connection between bedrock and soil aquifers, showed identical results of chemical analysis. Trace levels (BMDL) of Bis (2-ethyl hexel) phthalate and di-n-phthalate were the only compounds detected in water samples from these two wells. However, these samples were not tested for volatile organics.

8.9.3.2 Bedrock Aquifer

Ground water from three bedrock wells, MW-1D, MW-5D and MW-7D was sampled. Well MW-7D was analyzed for total priority pollutants and wells MW-1D and MW-5D were analyzed for base-neutral compounds only. All deep wells showed some degree of contamination. Wells MW-1D, MW-5D and MW-7D showed trace (BMDL) levels of several base neutral compounds. Well MW-7D showed 22 ppb of napthalene and approximately 1,300 ppb of total volatile organic contamination and 3,100 ppb of cyanide.

A complete list of all compounds detected in the ground water samples is presented in Tables 3 and 4.

Section 8.8 described the hydraulic relationship between the alluvial aquifer and the underlying bedrock aquifer and how the shallow alluvial aquifer ground water may be percolating into the bedrock aquifer in or near the northern part of the site in an area where there may be a "window" in the clay layer which separates the two aquifers. Ordinarily a clay layer, such as the one at the site, would act as a barrier to prevent significant migration of contaminants from an overlying to an underlying aquifer even in the presence of a strong vertical hydraulic gradient.

9.0 LOCAL WATER RESOURCES

9.1 SURFACE WATER

The Elizabeth River runs along the site's southern boundary. The river is subject to provision of NJAC 7:9-4, Surface Water Quality Standards, which establishes rules by which NJDEP classifies surface water bodies, provides for their designated uses and develops policy for protecting surface water bodies.

In accordance with Surface Water Quality Standards, the Elizabeth River has been classified as an SE-3 class waterway. The "SE" designation is the surface water classification applied to saline waters of estuaries, and the "3" indicates water with the fewest designated uses of the SE class. As such, designated uses of the Elizabeth River are restricted to:

1. Secondary contact recreation
2. Maintenance and migration of fish populations
3. Migration of diadromous fish
4. Maintenance of wildlife
5. Any other reasonable use

Less restrictive designated uses for SE-1 and SE-2 classified waters include primary contact recreation, shellfish harvesting and maintenance, migration and propagation of natural and established biota. These less restrictive uses are not applicable to the Elizabeth River.

On the basis of conversations held with NJDEP representatives, Ms. Barbara Curts and Messrs. Bud Cann and Ron Shearer of Division of Water Resources, Bureau of Monitoring Management, and Mr. Steven Lebow of Division of Water Resources, Bureau of Water Quality Standards, we understand that NJDEP does not have an active plan or strategy specifically designed to address potential problems associated with the Elizabeth River quality. Overall goals of the Department were described as improving the "fishability and swimability" of the river.

Although in our discussions, the NJDEP did not indicate specific aims with respect to improvement of the Elizabeth River as compared to other specific water bodies, general policy concerning surface water quality standards expressed in NJAC 7:9-4.5 include steps to improve overall quality of saline waters and prevent discharges of deleterious substances.

9.2 GROUND WATER

In the site area, ground water is found in both the bedrock and overburden. To evaluate ground water use in the site vicinity, Dames & Moore reviewed USGS Water Resources Investigation 76-73, Geology and Ground Water Resources of Union

County, New Jersey, held discussions with town engineers and health officials, and reviewed available well records on file at NJDEP Division of Water Resources. From these efforts, the location and use of identified wells and information concerning ground water use were evaluated. Figure 10 presents the locations of wells identified. A total of 29 well locations are provided on Figure 10. It should be noted that additional wells may also be present but not identified through our search.

Of the 29 well locations identified, six are reportedly used for domestic purposes, five are reportedly used as observation/monitoring wells, one is used as part of an air conditioning system, seven uses are unidentified (although six of these wells are owned by companies), four are reportedly unused, and six are used for industrial purposes. It is not known which, if any, of the wells are currently in use, however, the date of installation is shown on the attachment to Figure 10. Three wells are located within a 1/2-mile radius of the site. Two of these three wells are reportedly used for industrial purposes and one for domestic use. It is not known what aquifer is tapped by the domestic well but the reported depth, 92 feet, implies that the well is likely screened in bedrock. Specific yield ranged from 10 to 120 gallons per minute for these wells.

Seven additional well locations have been identified between a 1/2-mile and one mile radius of the site. The majority of these are located north and east of the site although wells are identified on all sides of the site. Two are reportedly used for domestic purposes, two for industrial use and uses of three are unknown. The depths of these wells indicate that six borings are screened in bedrock and one, located northwest of the site is an overburden monitoring well.

It should be noted that the City of Elizabeth is serviced by a public water supply. The public supply is provided to residents in the area of the site. No public supply well fields are located in the City of Elizabeth.

10.0 CONCLUSIONS

10.1 STRATIGRAPHY

- o Stratigraphy at the site consists of (with increasing depth below ground surface) fill, peat, residual soils, gravel, and bedrock. Unit thicknesses varies from 1 to 30 feet of fill, 0 to 6 feet of peat, 5 to 17 feet for residual soils, and 0 to 2 feet of gravel. In general, fill thickness increases to the south, the peat layer pinches out near the north central part of the site, and the gravel zone is present only along the Elizabeth River.

10.2 SOIL QUALITY

- o Oil-saturated soil and fill was encountered in the southern, western and central portions of the site.

- o Wood chips reportedly associated with coal gas purification were encountered on the ground surface and near surface fill.

- o Soil samples obtained from oil saturated soil zones contain residual compounds associated with coal gasification by-products.

- o More coal gasification by-product compounds were identified in the soil samples than in the water samples.

- o Coal tar constituents were detected in soil samples obtained from Borings B-3, B-7 and B-10.

10.3 GROUND WATER HYDROLOGY

- o Ground water is present in both the overburden and bedrock zones at the site.

- Ground water appears to flow radially away from the west central portion of the site.

- Water table elevations observed in the monitoring wells show variable response to rainfall events.

- Water level elevation fluctuations due to tidal response in the bedrock aquifer are on the order of .25 to .5 feet.

- Water table elevation fluctuations due to tidal response in the soil aquifer are negligible. MW-1 did, however, show cyclical changes in water levels which are attributable to tidal influences.

- The tidal response of shallow monitor well MW-1 in the northwest corner of the property (whereas no other shallow monitor wells have a tidal response even when close to the river) suggests that there is a hydraulic connection between the alluvial aquifer and the bedrock aquifer somewhere close to the location of MW-1.

- A former gas tank pit has been excavated approximately 15 feet into bedrock at MW-2. The pit has been backfilled with fill and silty clay materials, which may limit the hydraulic connection with the bedrock aquifer.

- The average hydraulic gradient is downward from the alluvial aquifer to the bedrock aquifer under much of the site.

10.4 GROUND WATER QUALITY

- Oily materials occasionally have been observed to seep from the alluvial aquifer along the Elizabeth River at low tide when the water level in the river is lower than the ground water level in the alluvial aquifer.

- o Coal tar constituents were identified at detectable levels in ground water samples obtained from monitoring wells 2, 4, 5, 6, 7, 9, 10 and 7D. Coal tar constituents were identified at levels below method detection limits in monitoring wells 1, 3, 8, 1D and 5D.

- o Compounds detected are those associated with coal tars. An off-site source of pollution may exist but has not yet been confirmed.

- o The "plus 40" analysis of selected water and soil samples qualified but did not quantify additional compounds associated with coal tars.

- o Cyanide is present in the ground water and was detected in wells MW-2, MW-5, MW-7 and MW-7D which were tested for this compound.

10.5 WATER RESOURCES

- o The Elizabeth River adjacent to the site is classified by NJDEP as an SE-3 designated river with limited designated uses.

- o No municipal water supply well fields were identified in Elizabeth although several private wells were identified in the site vicinity.

TABLES

TABLE 1

WATER LEVEL ELEVATIONS
ERIE STREET
ELIZABETHTOWN GAS COMPANY
ELIZABETH, NEW JERSEY

Monitor Well	Elevation of Top of Casing (feet)	Water Elevations (Feet Above Mean Sea Level)								
		10/17/84	11/01/84	01/17/85	05/02/86	08/26/87	08/29/86	09/02/86	09/05/86	09/11/86
MW-1	12.58	3.90	3.57	4.17	4.95	4.21	3.84	3.97	3.99	3.80
MW-1D	12.86	3.49	3.00	3.71	4.22	3.66	3.22	3.54	3.63	3.33
MW-2	10.96	5.41	5.77	5.92	5.78	6.23	6.01	5.72	5.71	5.96
MW-3	9.62	2.98	3.42	3.51	4.14	3.87	3.52	3.25	3.20	3.41
MW-4	14.19	5.66	5.47	5.60	7.31	7.14	7.00	6.79	6.75	6.78
MW-5	9.47	3.16	2.60	2.76	—	3.56	3.51	3.37	3.44	3.41
MW-5D	9.43	3.23	2.99	3.44	4.11	3.56	3.14	3.35	3.61	3.28
MW-6	9.08	3.35	3.08	3.15	—	4.08	3.97	3.81	3.80	3.78
MW-7	10.70	2.93	2.70	2.55	3.40	3.22	3.13	2.90	3.01	3.06
MW-7D	9.41	0.54	0.04	0.86	1.55	0.69	0.48	0.49	0.75	0.68
MW-8	12.71	4.47	4.61	4.95	5.46	5.29	4.90	4.86	4.90	4.99
MW-9	12.27	4.91	4.79	5.08	6.92	6.84	6.76	6.45	6.41	6.47
MW-10	12.03	5.43	5.30	5.44	6.95	7.20	6.85	6.84	6.86	7.03

TABLE 2

SUMMARY OF ANALYSES (in ppb[1])
SOIL/WASTE MATRIX SAMPLES

ERIE STREET
ELIZABETHTOWN GAS COMPANY
ELIZABETH, NEW JERSEY

	B-3		B-7		B-10	
VOLATILE COMPOUNDS						
Benzene	6,280	(5,000)	BMDL	(2,000)	1,380	(500)
Chlorobenzene			BMDL	(2,000)		
Ethylbenzene	52,900	(5,000)	2,830	(2,000)	2,740	(500)
Methylene Chloride	BMDL	(5,000)	BMDL	(2,000)		
Toluene	BMDL	(5,000)	13,000	(2,000)	4,820	(500)
1,1,1-Trichloroethane	BMDL	(5,000)				
BASE/NEUTRAL COMPOUNDS						
Acenaphthene	34,200	(3,230)	57,500	(14,300)	527,000	(14,300)
Acenaphthylene			82,800	(14,300)	288,000	(14,300)
Anthracene	18,900	(3,230)	117,000	(14,300)	448,000	(14,300)
Benzo (a) Anthracene	78,300	(3,230)	188,000	(14,300)	581,000	(14,300)
Benzo (a) Pyrene	35,100	(3,230)	68,000	(14,300)	278,000	(14,300)
Benzo (b) Fluoroanthene	38,700	(3,230)	83,800	(14,300)	272,000	(14,300)
Benzo (ghi) Perylene	25,900	(3,230)	57,000	(14,300)	168,000	(14,300)
Benzo (k) Fluoroanthene	8,070	(3,230)	53,800	(14,300)	71,800	(14,300)
Chrysene	31,700	(3,230)	87,000	(14,300)	200,000	(14,300)
Dibenzo (a,h) Anthracene	8,740	(3,230)	BMDL	(14,300)	51,800	(14,300)
Fluoranthene	28,100	(3,230)	138,000	(14,300)	443,000	(14,300)
Fluorene	20,400	(3,230)	191,000	(14,300)	528,000	(14,300)
Indeno (1,2,3-c,d) Pyrene	14,200	(3,230)	28,100	(14,300)	96,400	(14,300)
Naphthalene	183,000	(3,230)	2,430,000	(14,300)	1,158,000	(14,300)
Phenanthrene	84,500	(3,230)	636,000	(14,300)	1,818,000	(14,300)
Pyrene	46,800	(3,230)	211,000	(14,300)	726,000	(14,300)
ACID COMPOUNDS						
Phenol	BMDL	(807)				
METALS, CYANIDE AND PHENOL (parts per million)						
Antimony	BMDL	(6)	BMDL	(6)	BMDL	(6)
Arsenic	6.70	(1)	18	(.50)	8.30	(3)
Beryllium	BMDL	(.50)	BMDL	(.50)	0.70	(.5)
Cadmium	BMDL	(.50)			BMDL	(.5)
Chromium	7.80	(1)	43	(1)	26	(1)
Copper	47	(.90)	220	(.90)	30	(.90)
Lead	120	(4)	89	(4)	52	(4)
Mercury	BMDL	(.10)	BMDL	(.10)	BMDL	(.10)
Nickel	13	(.70)	46	(.70)	19	(.70)
Selenium	3.10	(1)	8.70	(.50)	5.80	(3)
Silver	1.70	(.60)	BMDL	(.60)	BMDL	(.60)
Thallium	BMDL	(.50)	BMDL	(.50)		
Zinc	82	(.60)	23	(.60)	31	(.60)
Cyanide, Total	7.80	(.50)	118	(.50)	14	(.50)
Phenolics, Total	34	(.10)	128	(.10)	29	(.10)

Notes:

1) Concentrations shown are in parts per billing (ppb) unless otherwise specified.
2) "E+05" = scientific notation. Decimal point lies five places to the right.
3) Blank spaces indicate compound not detected in that sample.
4) BMDL - Below Method Detection Limit of analysis.
5) Figures in parenthesis are detection limit of analysis.

TABLE 3

SUMMARY OF ANALYSIS
BASE NEUTRAL COMPOUNDS IN GROUND WATER

ERIE STREET
ELIZABETHTOWN GAS COMPANY
ELIZABETH, NEW JERSEY

	MW-1	MW-1D	MW-3	MW-4	MW-5D	MW-6	MW-8	MW-9	MW-10
Acenaphthene				176	BMDL	24	BMDL	BMDL	83
Acenephthylene				BMDL	BMDL	BMDL		BMDL	104
Anthracene				12		BMDL		BMDL	22
Benzo (a) Anthracene				BMDL					16
Benzo (a) Pyrene									BMDL
Benzo (b) Fluoroanthene									BMDL
Bis (2-Ethylhaxyl) Phthalate	BMDL	BMDL	BMDL	BMDL	BMDL	BMDL	BMDL	12	BMDL
Butyl Benzyl Phthalate								BMDL	
Chrysene				BMDL					BMDL
Di-n-butyl Phthalate	BMDL	BMDL	BMDL	BMDL	BMDL		BMDL	BMDL	BMDL
Di-n-octyl Phthalate			BMDL						
Fluoranthene				BMDL				BMDL	21
Fluorene				47		BMDL		BMDL	76
Napthalene				3,420	BMDL	32		424	1,840
Phenanthrene				80		BMDL		BMDL	130
Pyrene				11	BMDL	BMDL		BMDL	39

Notes

Concentrations shown are in parts per billion (ppb).
Blank spaces indicate compound not detected in that sample.
BMDL = Below Method Detection Limit of Analysis.
Detection limit of analysis - 10 ppb.
Results of Analysis for Base Neutrals in MW-2, MW-5, MW-7 are included in Table 4.

TABLE 4

SUMMARY OF ANALYSIS
MW-2, MW-5, MW-7 AND MW-7D

ERIE STREET
ELIZABETHTOWN GAS COMPANY
ELIZABETH, NEW JERSEY

	MW-2		MW-5		MW-7		MW-7D	
Volatile Compounds								
Benzene	530	(10)	529	(10)	785	(100)	778	(100)
Ethylbenzene					398	(100)	188	(100)
Methylene Chloride	BMDL	(10)	BMDL	(10)				
Tetrachloroethylene	BMDL	(10)						
Toluene	214	(10)	19	(10)	BMDL	(100)	402	(100)
Base/Neutral Compounds								
Acenaphthene	78	(10)	125	(10)	13	(10)		
Acenaphthylene	104	(10)	17	(10)				
Anthracene	11	(10)	14	(10)	BMDL	(10)		
Benzo (a) Anthracene			BMDL	(10)				
Chrysene	BMDL	(10)	BMDL	(10)				
Fluoranthene	BMDL	(10)	BMDL	(10)				
Fluorene	42	(10)	37	(10)			BMDL	(10)
Naphthalene	1390	(10)	142	(10)	1380	(10)	22	(10)
Phenanthrene	55	(10)	91	(10)	11	(10)	BMDL	(10)
Pyrene	BMDL	(10)	15	(10)	BMDL	(10)		
Acid Compounds								
2,4-Dimethylphenol	BMDL	(25)	BMDL	(25)	BMDL	(25)		
Phenol	BMDL	(25)						
Metals, Cyanide and Phenols								
Arsenic	410	(5)	BMDL	(10)			BMDL	(5)
Chromium					17	(8)		
Copper	BMDL	(8)			BMDL	(8)		
Thallium			BMDL	(5)			7.08	(5)
Cyanide, Total	560	(25)	400	(25)	14,000	(25)	3100	(25)
Phenolics, Total	63	(50)	50	(50)	86	(50)	84	(50)

Notes:

Concentrations shown are in parts per billion (ppb).

Blank spaces indicate compound not detected in that sample.

BMDL = Below Method Detection Limit of analysis.

Figures in parenthesis are detection limit of analysis.

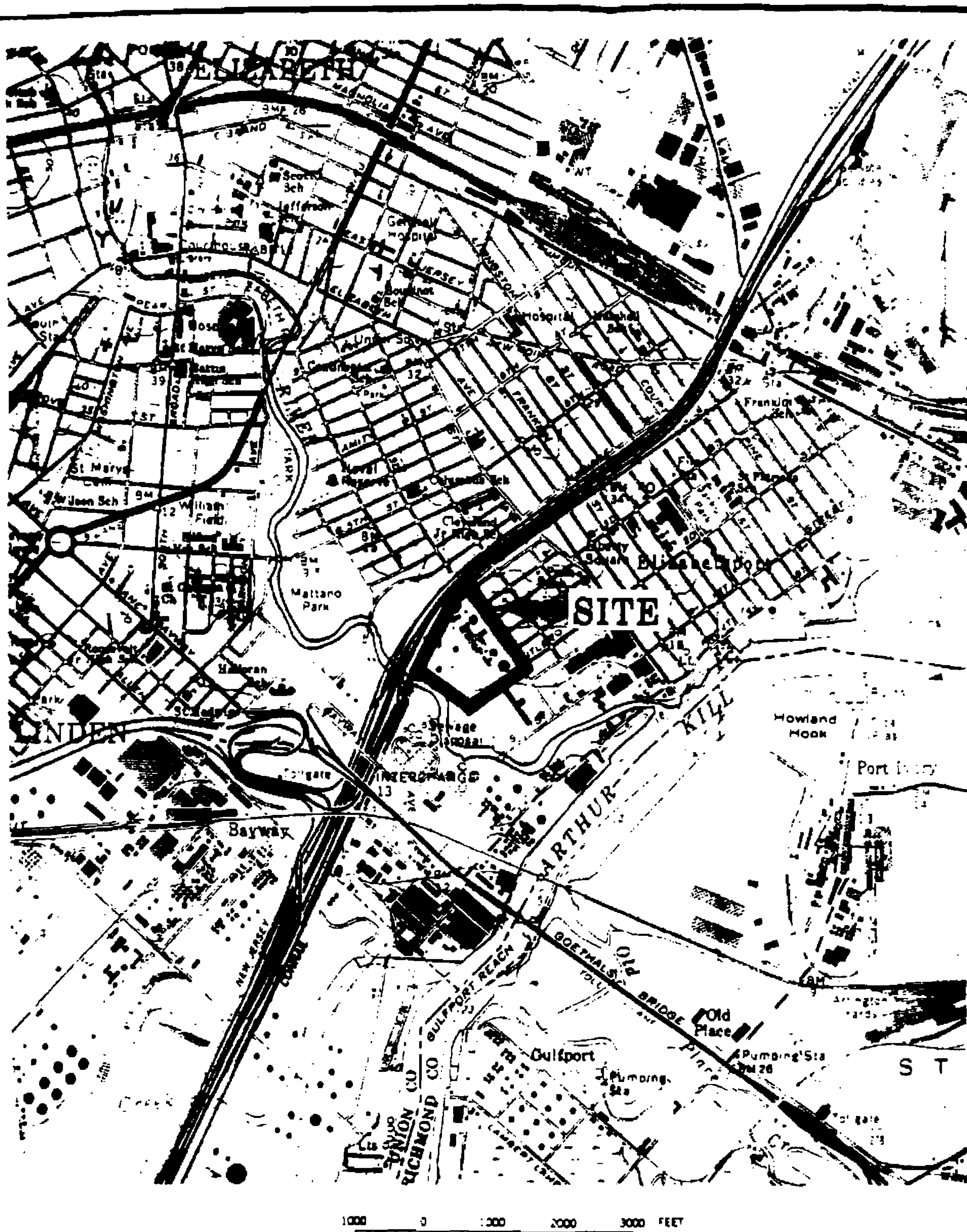
TABLE 5

SPECIFIC CAPACITY OF MONITOR WELLS

ERIE STREET
ELIZABETHTOWN GAS COMPANY
ELIZABETH, NEW JERSEY

Well No.	Pumping Rate (gpm)	Drawdown at 10 Minutes (feet)	Specific Capacity (gpm/ft of Drawdown)
MW-1	1	8.57	0.12
MW-1D	10	1.16	8.62
MW-2	5	ran dry	—
MW-3	5	ran dry	—
MW-4	10	0.05	200.0
MW-5	5	.35	14.3
MW-5D	10	4.60	2.17
MW-6	5	.11	45.5
MW-7	5	ran dry	—
MW-7D	3.5	8.54	0.41
MW-8	5	ran dry	—
MW-9	5	5.75	0.87
MW-10	10	.30	33.3

FIGURES

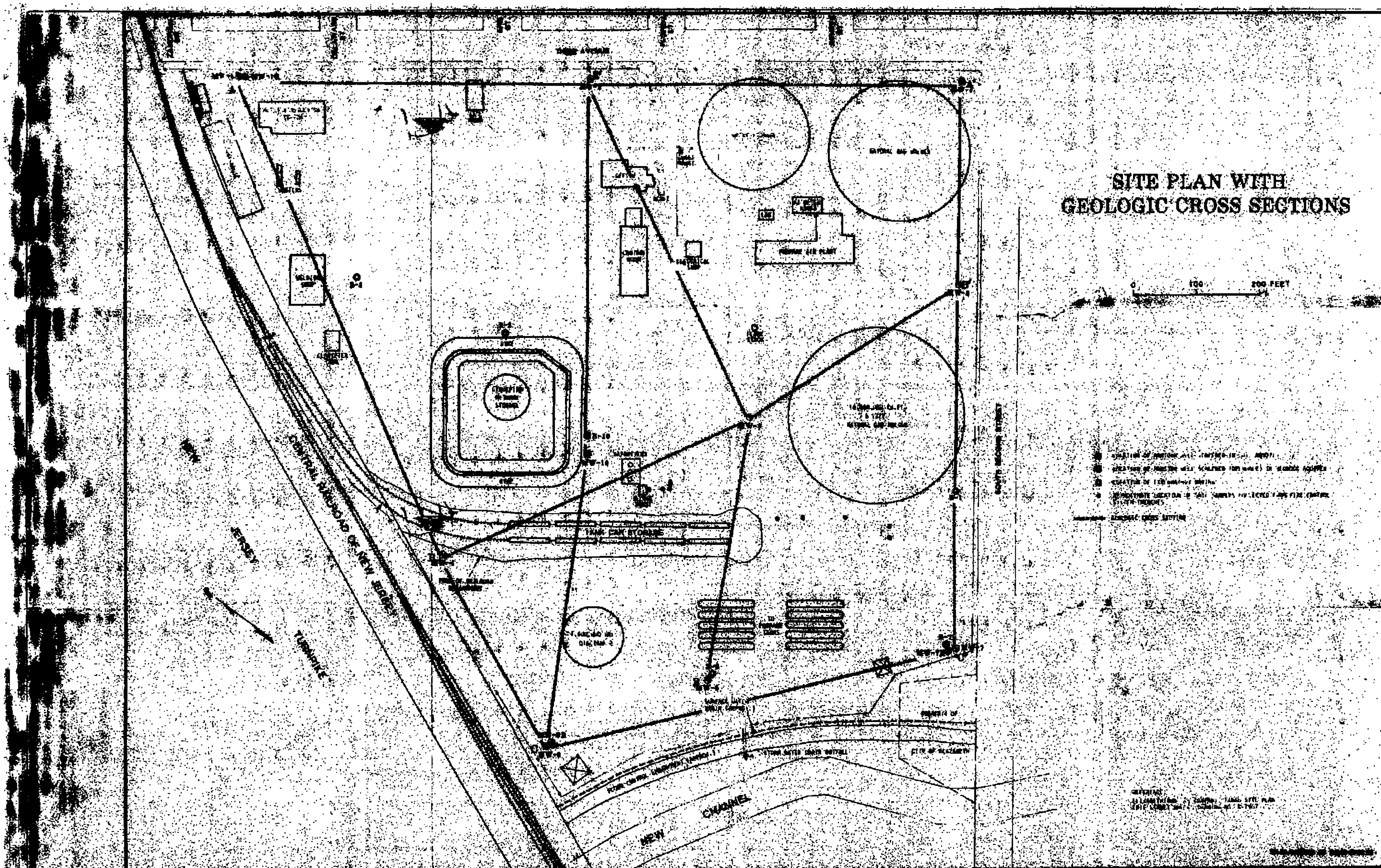


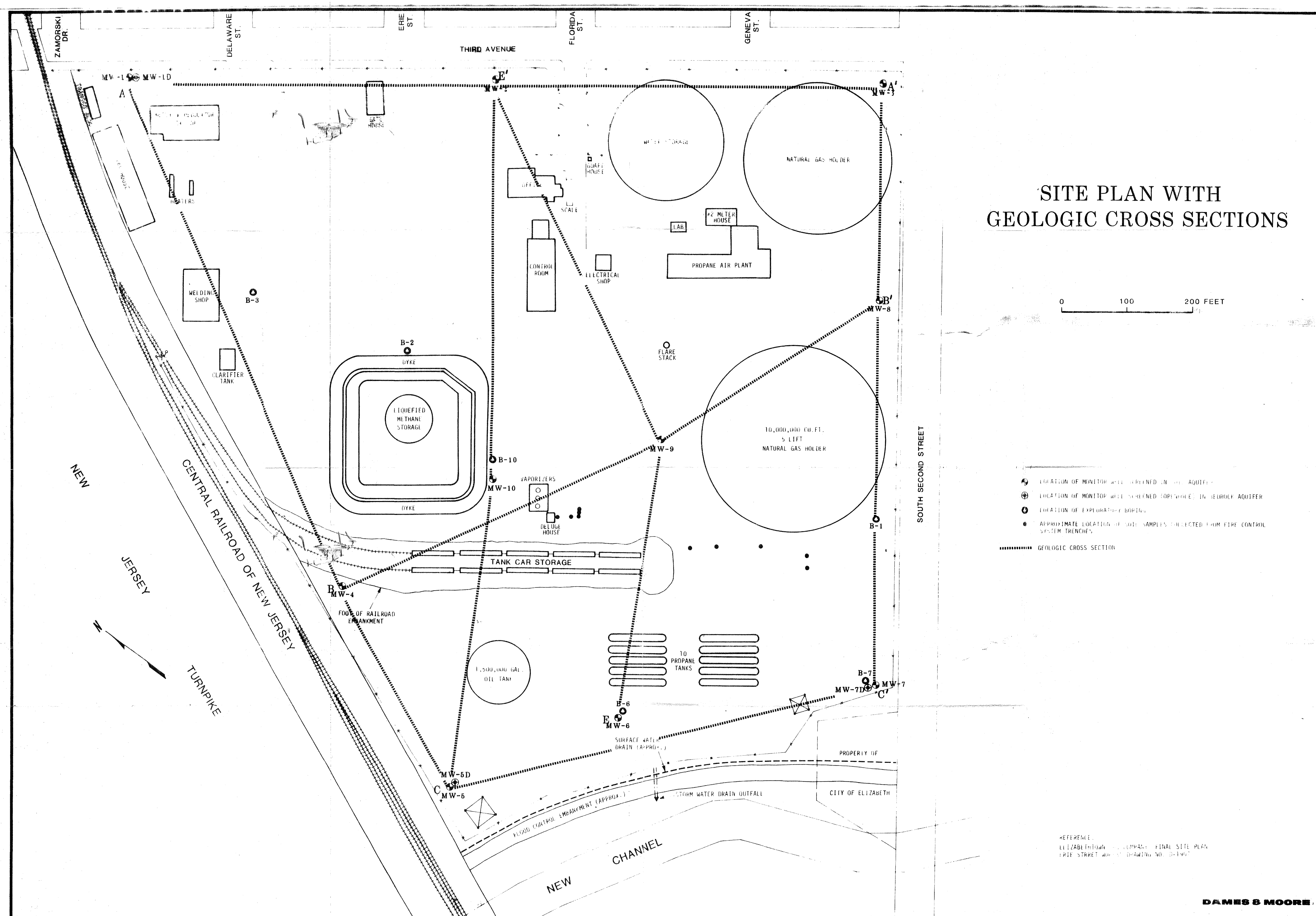
LOCATION MAP
ERIE STREET FACILITY
ELIZABETHTOWN GAS COMPANY

SOURCE: TAKEN FROM U.S.G.S. 7½ QUAD
ELIZABETH, N.J.-N.Y., 1967, PHOTO REV. 1981.

DAMES & MOORE

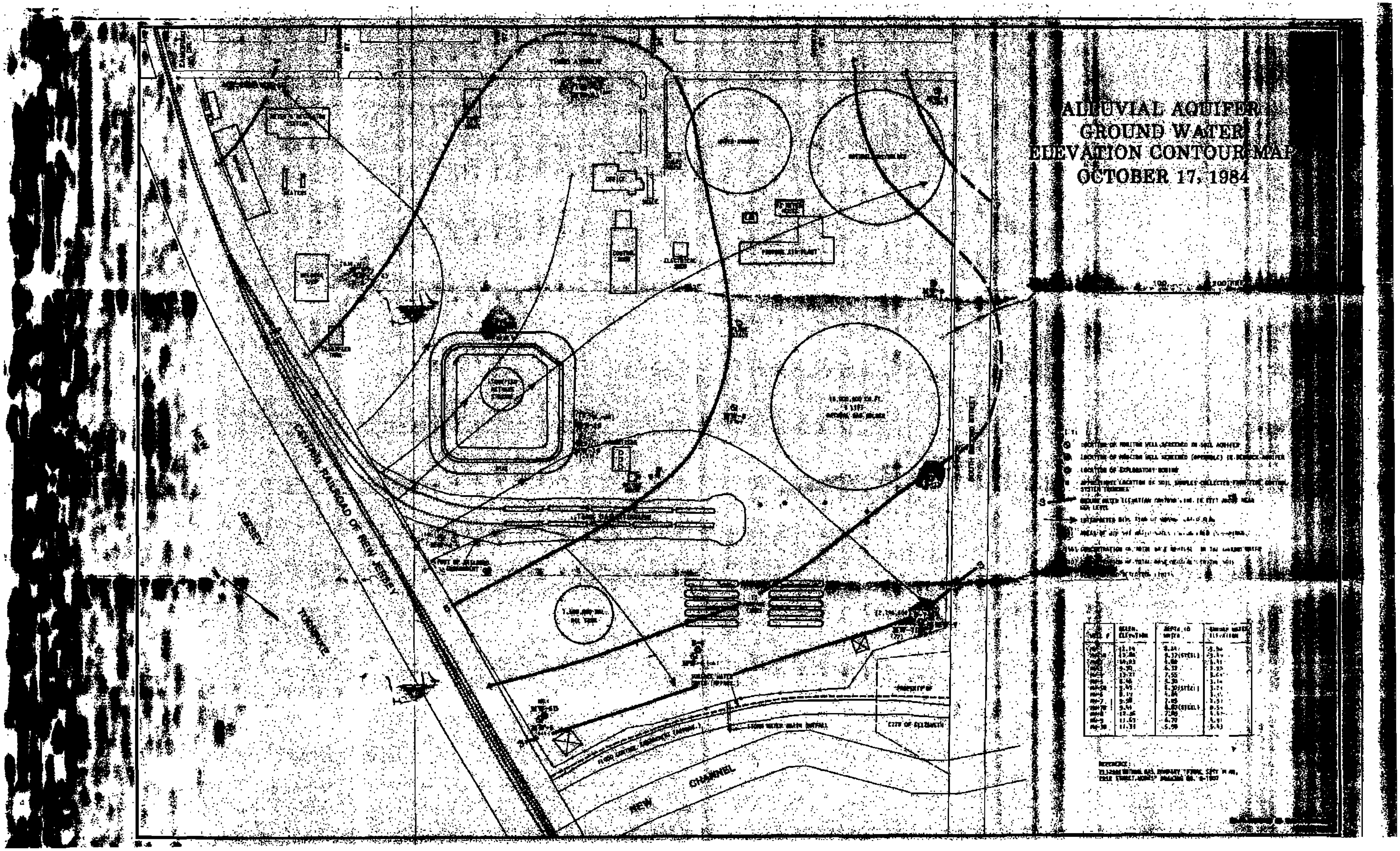
FIGURE 1

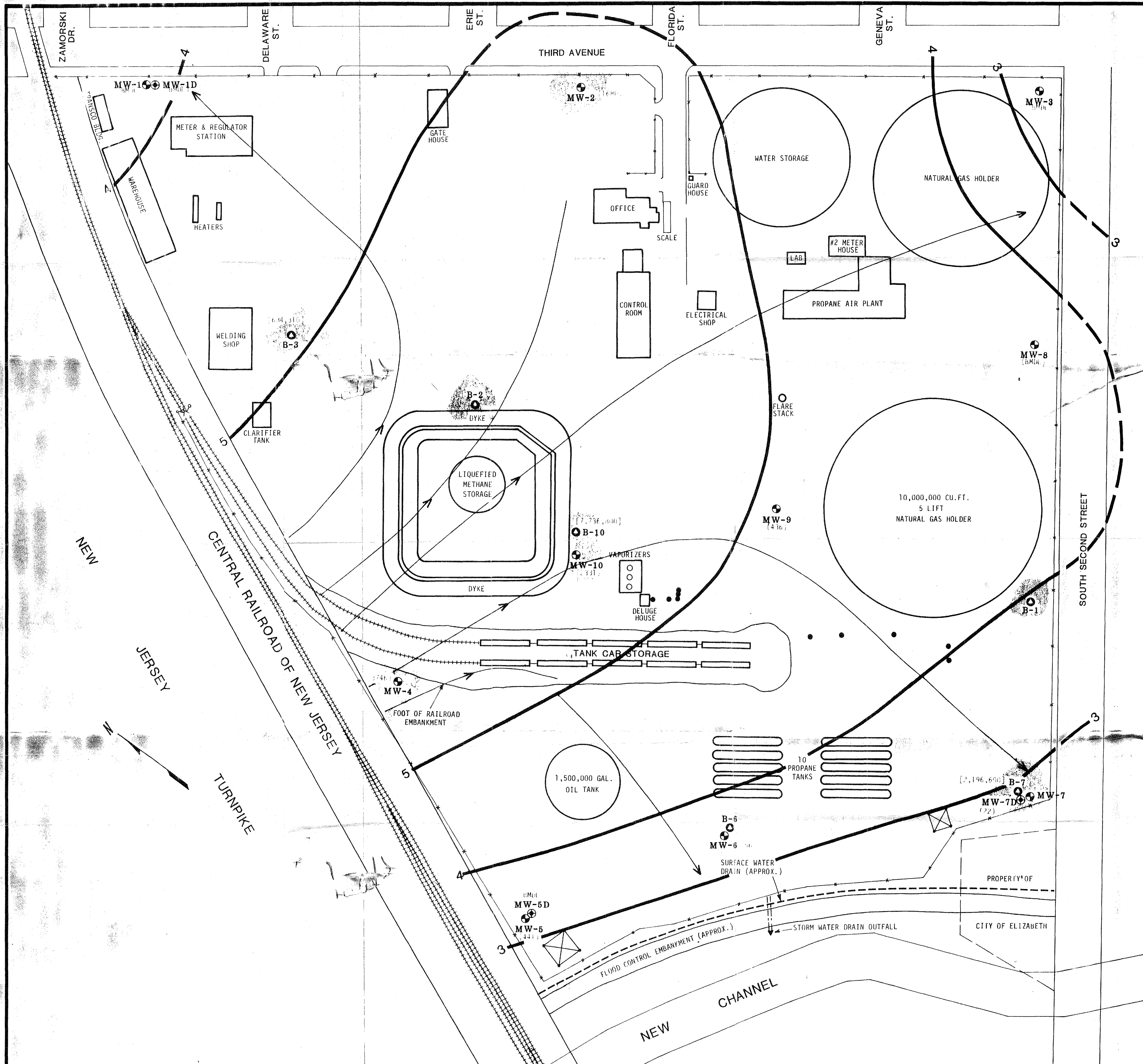

SITE PLAN WITH
GEOLOGIC CROSS SECTIONS
TANK CAR STORAGE
NEW JERSEY TURNPIKE
CENTRAL RAILROAD OF NEW JERSEY
NEW CHANNEL
0
100
200 FEET
FIGURE 2



SITE PLAN WITH GEOLOGIC CROSS SECTIONS

FIGURE 2


ALLUVIAL AQUIFER
GROUND WATER
ELEVATION CONTOUR MAP
OCTOBER 17, 1984
NEW JERSEY TURNPIKE
CENTRAL RAILROAD OF NEW JERSEY
NEW CHANNEL



ALLUVIAL AQUIFER GROUND WATER ELEVATION CONTOUR MAP OCTOBER 17, 1984

KEY:

- LOCATION OF MONITOR WELL SCREENED IN SOIL AQUIFER
- LOCATION OF MONITOR WELL SCREENED (OPENHOLE) IN BEDROCK AQUIFER
- LOCATION OF EXPLORATORY BORING
- APPROXIMATE LOCATION OF SOIL SAMPLES COLLECTED FROM FIRE CONTROL SYSTEM TRENCHES
- 3 GROUND WATER ELEVATION CONTOUR LINE IN FEET ABOVE MEAN SEA LEVEL
- INTERPRETED DIRECTION OF GROUND WATER FLOW
- AREAS OF OIL SATURATED SOILS ENCOUNTERED IN BORINGS
- (56) CONCENTRATION OF TOTAL BASE NEUTRALS IN THE GROUND WATER
- [634,310] CONCENTRATION OF TOTAL BASE NEUTRALS IN THE SOIL
- (BMDL) BELOW METHOD DETECTION LIMITS

WELL #	REFER. ELEVATION	DEPTH TO WATER	GROUND WATER ELEVATION
MW-1	12.14	8.24	3.9[illegible]
MW-1D	12.86	9.37(STEEL)	3.4[illegible]
MW-2	10.23	4.82	5.4[illegible]
MW-3	9.30	6.32	2.9[illegible]
MW-4	13.21	7.55	5.6[illegible]
MW-5	8.46	5.30	3.1[illegible]
MW-5D	9.43	6.30(STEEL)	3.2[illegible]
MW-6	8.19	4.84	3.[illegible]
MW-7	9.98	7.05	2.9[illegible]
MW-7D	9.41	8.87(STEEL)	0.5[illegible]
MW-8	12.36	7.89	4.4[illegible]
MW-9	11.63	6.72	4.91
MW-10	11.33	5.90	5.43

REFERENCE:
ELIZABETHTOWN GAS COMPANY "FINAL SITE PLAN, ERIE STREET WORKS" DRAWING NO. D-1907

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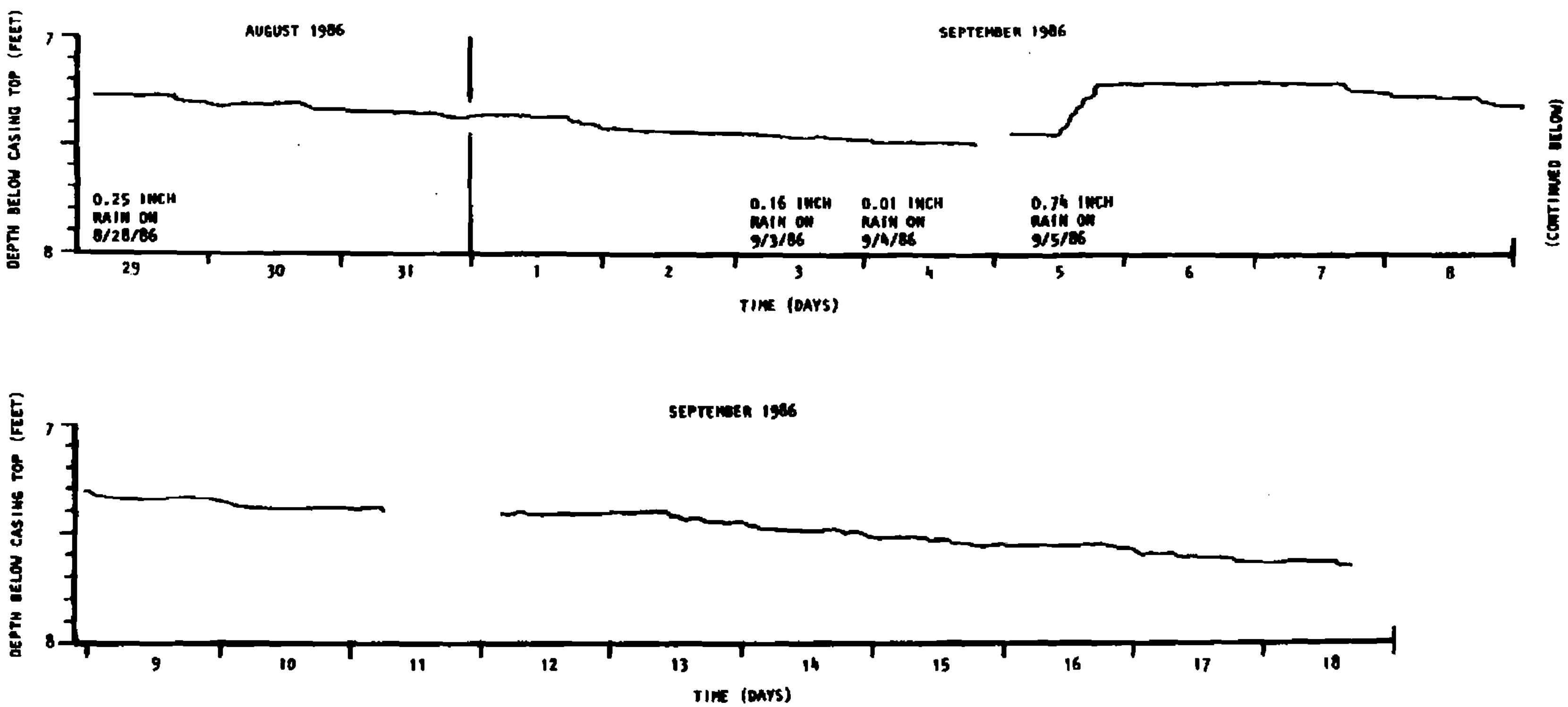
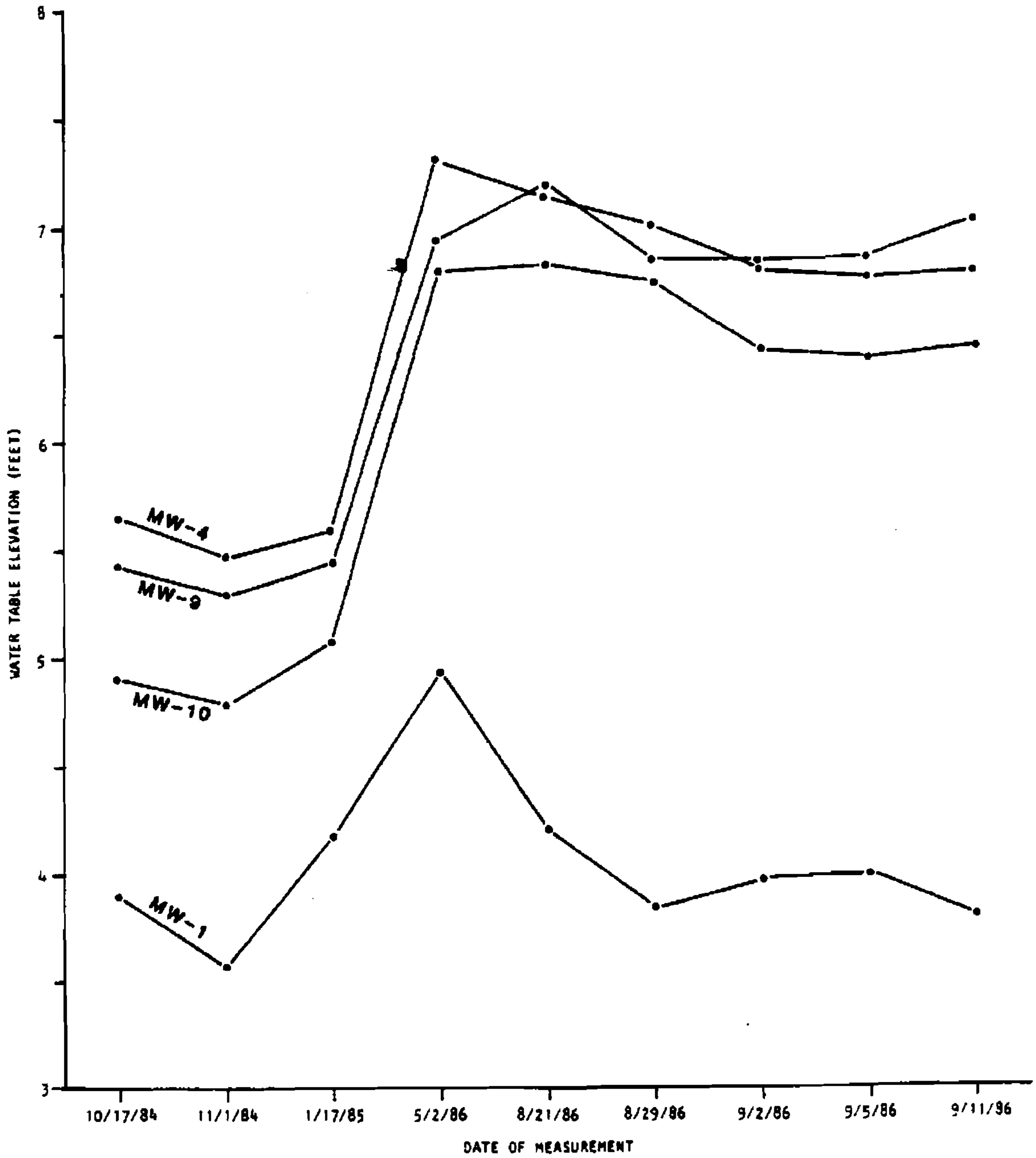
FIGURE 4



WATER LEVEL HYDROGRAPH
MONITOR WELL MW-4
AUGUST-SEPTEMBER 1986
ERIE STREET SITE
ELIZABETHTOWN GAS CO.
ELIZABETH, N.J.

FIGURE 5

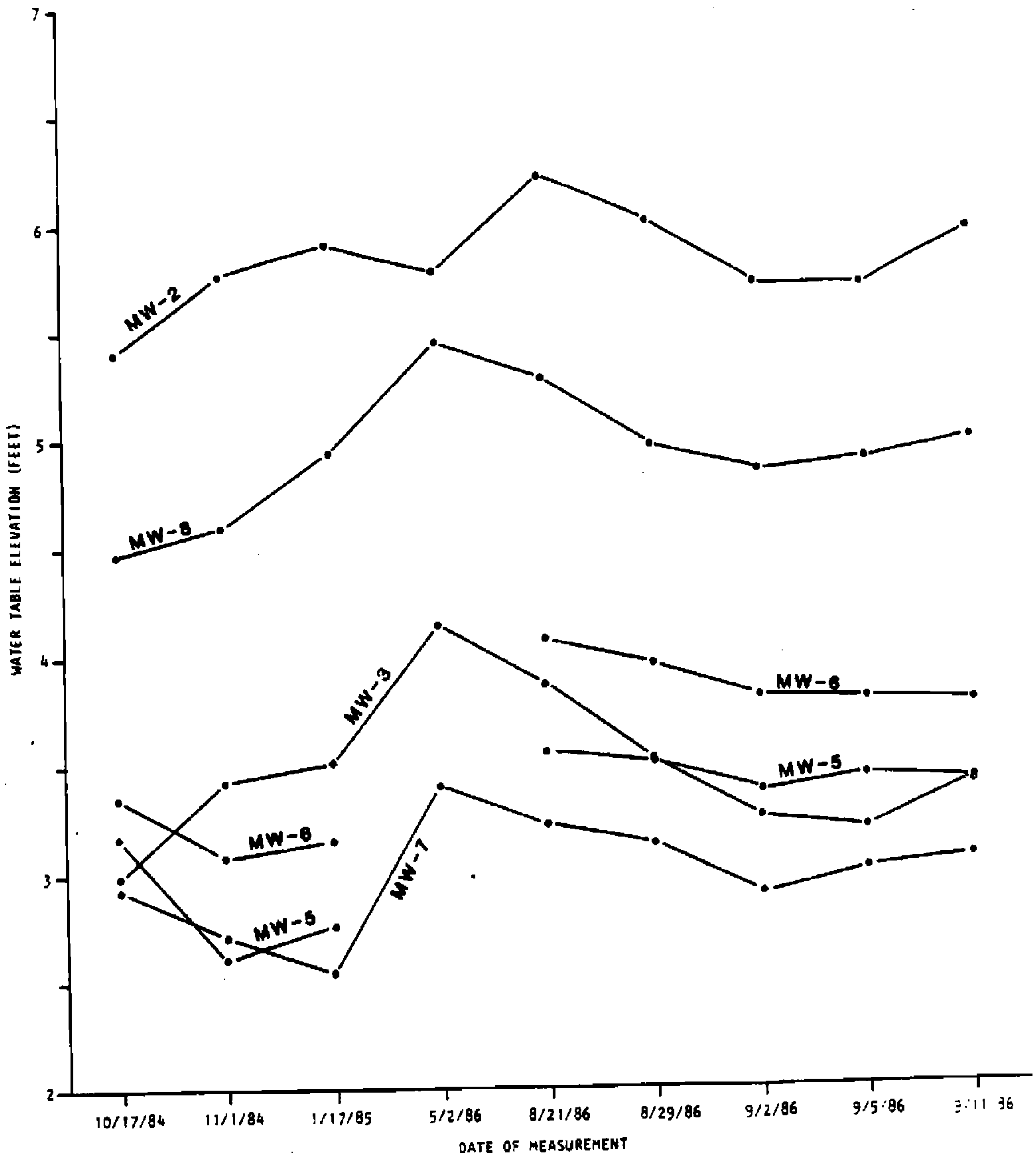


WATER LEVEL HYDROGRAPHS FOR SHALLOW MONITOR WELLS
1984-1986

ELIZABETHTOWN GAS CO.
ERIE STREET SITE
ELIZABETH, N.J.

NOTE: HORIZONTAL AXIS NOT TO SCALE

FIGURE 6A



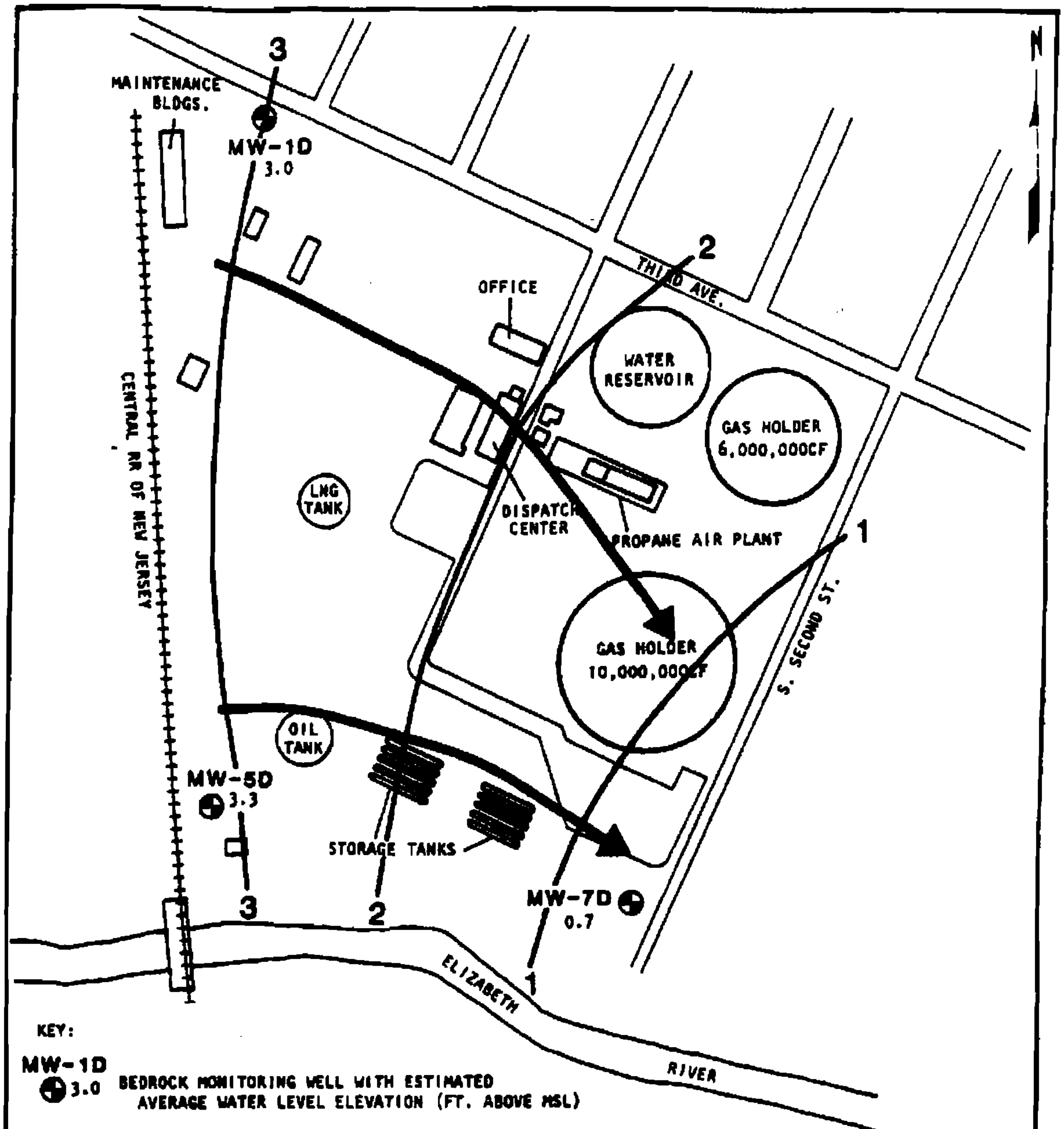
WATER LEVEL HYDROGRAPHS FOR SHALLOW MONITOR WELLS
1984-1986

ELIZABETHTOWN GAS CO.

ERIE STREET SITE

ELIZABETH, N.J.

NOTE: HORIZONTAL AXIS NOT TO SCALE



KEY:

MW-1D 3.0 BEDROCK MONITORING WELL WITH ESTIMATED AVERAGE WATER LEVEL ELEVATION (FT. ABOVE MSL)

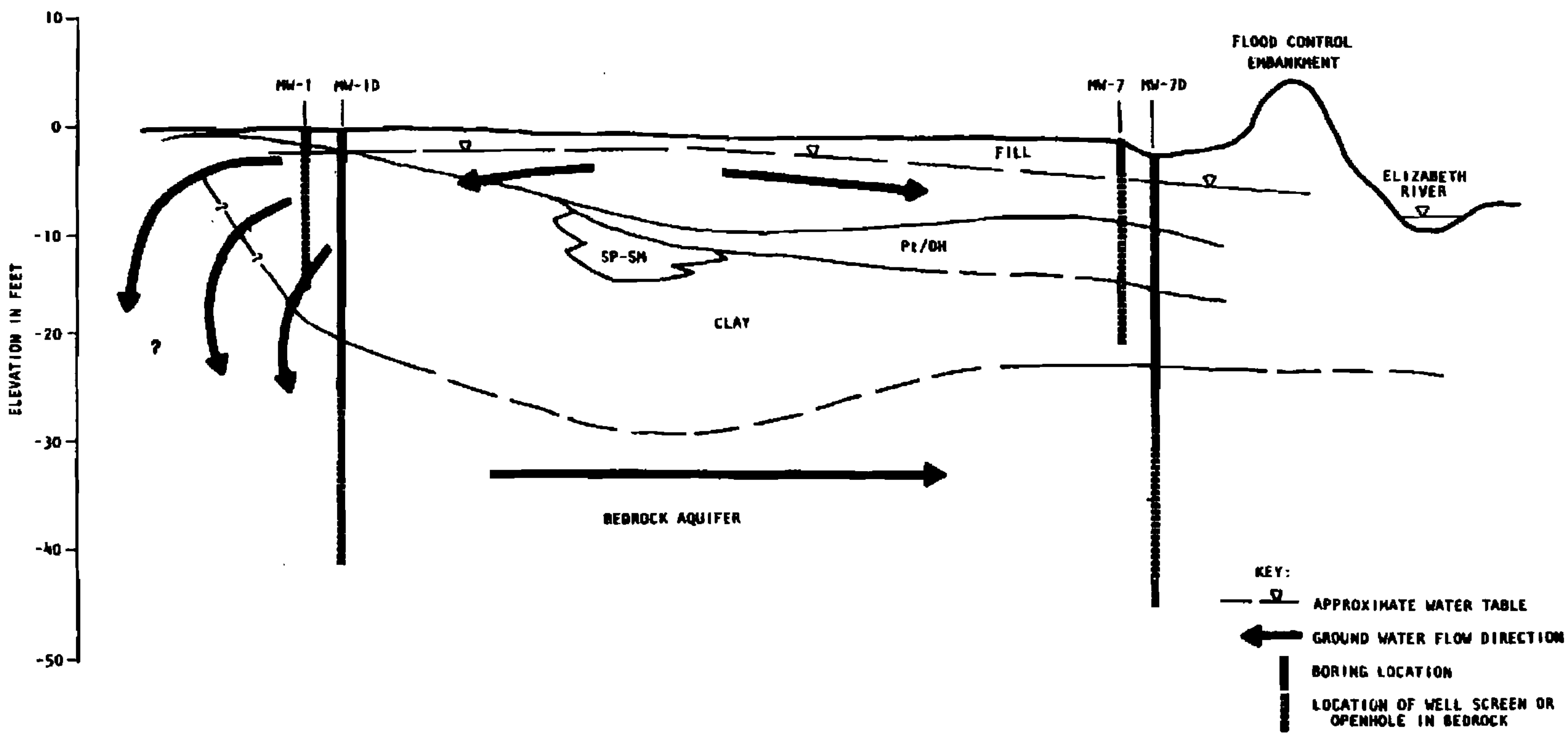
2 ESTIMATED AVERAGE WATER LEVEL CONTOUR IN BEDROCK

ESTIMATED AVERAGE GROUND WATER FLOW DIRECTION

ESTIMATED AVERAGE WATER LEVEL CONTOURS IN BEDROCK AQUIFER WINTER 1984

ELIZABETHTOWN GAS CO.
ERIE STREET FACILITY
ELIZABETH, N.J.

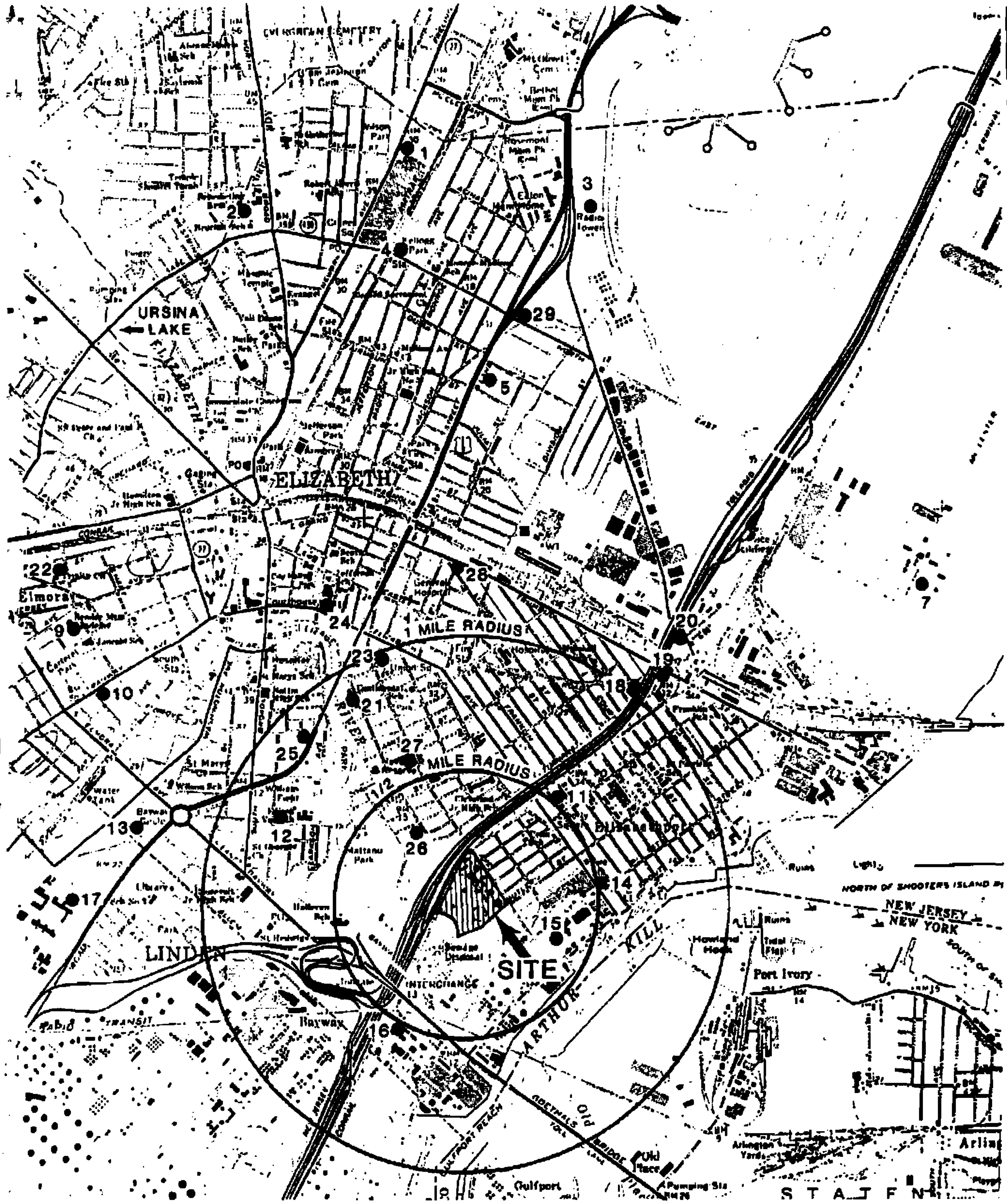
FIGURE 8



GENERALIZED CROSS SECTION
SHOWING POSSIBLE HYDRAULIC CONNECTION
BETWEEN ALLUVIAL AND BEDROCK AQUIFERS

ELIZABETHTOWN GAS CO.
ERIE STREET FACILITY
ELIZABETH, N.J.

FIGURE 9



LOCAL WELL LOCATION MAP

ELIZABETHTOWN GAS CO.
ELIZABETH, N.J.

0 2000 4000 FEET

REFERENCE:
GEOLOGY AND GROUNDWATER RESOURCES OF UNION COUNTY, N.J., USGS WATER RESOURCES INVESTIGATION 76-73. NJDEP FILES.
BASE MAP: USGS TOPOGRAPHIC MAP., ELIZABETH, N.J.-N.Y. QUADRANGLE, 1967.

KEY:
● 5 LOCATION OF IDENTIFIED WELL

NOTE:
SEE FOLLOWING PAGE FOR LIST OF WELL OWNERS AND WELL USE. ADDITIONAL WELLS MAY BE PRESENT AND NOT DEPICTED ON THE FIGURE.

WELLS IDENTIFIED IN SITE AREA

Well No.	Owner	Date Drilled	Well Depth (ft)	Geologic Unit Tapped	Yield (gpm)	Use
1	Schweitzer, Inc.	—	660	Bedrock	--	Unused
2	Elizabethtown Water Co.	1953	202	Bedrock	--	Unused
3	Black Diamond Co.	1960	265	Bedrock	150	Industrial
4	Elizabeth Water Co.	1953	203	Bedrock	--	—
5	Londet Aetz Co.	1965	300	Bedrock	30	Unused
6	Wm. Einhorn	1954	110	Bedrock	15	Domestic
7	General Chemical Co.	1965	500	Bedrock	70	Unused
8	Leland Tube Co.	1965	500	Bedrock	100	Industrial
9	Joseph Waldo	1953	150	Bedrock	12	Domestic
10	J. E. Bryan	1950	255	Bedrock	60	Domestic
11	Thomas-Betts Co.	1959	500	Bedrock	284	Other
12	M. Marcus	1952	600	Bedrock	80	Industrial
13	Volupte, Inc.	1952	490	Bedrock	24	—
14	Exact Anadiz Co.	1965	467	Bedrock	--	Industrial
15	Perk Chemical Co., Inc.	1965	285	Bedrock	120	Industrial
16	Reichold Chemical Co.	1967	400	Bedrock	415	Industrial
17	Converters Ink Co., Inc.	1986	5-14	—	--	Monitoring
18	New Jersey Turnpike	1987	58	—	--	Monitoring
19	New Jersey Turnpike	1987	44	—	--	Monitoring
20	New Jersey Turnpike	1987	65	—	--	Monitoring
21	St. Anthony's Ball Field	1966	200	—	15	Domestic
22	Trinity Pentecostal Church	1961	200	—	56	Air Conditioning
23	Bernard Goodman	—	122	—	12	—
24	Shell Oil	1983	8-18	—	--	—
25	Exxon	1984	10	—	--	--
26	Joe Basille	1958	92	—	10	Domestic
27	Peter Florini	1955	89	—	10	Domestic
28	Exxon	1984	10	--	--	Observation
29	Exxon	1986	13	—	--	—

NOTES:

Refer to Figure 10 for well locations.

-- = Unknown

Wells Nos. 6 and 8 are located outside map boundaries on Figure 10.